ORIGINAL

E000015052

MEMORANDUM

TO: Docket Control

FROM: Elijah O. Abinah
Director
Utilities Division

DATE: August 11, 2021

RE: IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2019, 2020, AND 2021. (DOCKET NO. E-00000V-19-0034)

SUBJECT: REDACTED VERSION OF THIRD-PARTY ANALYST'S INDEPENDENT REVIEW OF 2020 INTEGRATED RESOURCE PLANS AND ANALYSIS OF THE COMMISSION'S PROPOSED ENERGY RULES.

Pursuant to Arizona Corporation Commission ("ACC" or "Commission") Decision No. 76632, Commission Utilities Division Staff ("Staff") engaged Ascend Analytics ("Ascend") and Verdant Associates ("Verdant") (combined "the Ascend team") to conduct an independent review of the scenarios and portfolios presented in each Load Serving Entity's ("LSE") 2020 Integrated Resource Plan ("IRP"), and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the Ascend team deemed were not adequately represented or considered in the 2020 IRPs.

Attached is a redacted copy of the Ascend team's independent review of the 2020 IRPs filed by Arizona Public Service ("APS"), Tucson Electric Power ("TEP"), and UNS Electric ("UNSE"). In addition, the independent review includes a preliminary analysis of the cost of adopting resource portfolios consistent with the Commission's proposed Energy Rules (Decision No. 78041) and a hypothetical "least-cost" portfolio. The Ascend team worked with APS, TEP, and UNSE to develop expansion plans through 2050 in order to calculate the cost impacts of complying with the proposed Energy Rules. The Energy Rules initially required a 100 percent reduction in greenhouse gas ("GHG") emissions by 2050. Subsequent action by the ACC reduced the requirement to 80 percent by 2050 and 100 percent by 2070. The utilities modeled the following cases through 2050:

- 80 percent reduction in GHG emissions by 2050
- 100 percent reduction in GHG emissions by 2050
- "Least-cost" portfolio through 2050

Results for APS and TEP have been included in the attached report. The results for UNSE will be filed in the docket in a supplemental report by the Ascend team.

ACC - Docket Control - Received 8/11/2021 12:45 PM
ACC - Docket Control - Docketed 8/11/2021 1:15 PM

Staff is currently reviewing the attached report and will include a discussion in its Staff Assessment and Proposed Order that will be filed shortly after the Ascend team submits its supplemental report containing results for UNSE.

EOA:ZTB:la/MAS

Originator: Zachary Branum

Attachments

On this 11th day of August 2021, the foregoing document was filed with Docket Control as a Utilities Division Memorandum, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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Ascend Analytics

Better models. Better decisions.

REDACTED

REPORT

Arizona Utility Integrated Resource Plan Review

PREPARED FOR:

ARIZONA CORPORATION COMMISSION

AUGUST 10, 2021

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Executive Summary

The Arizona Corporation Commission ("ACC" or "Commission") engaged Ascend Analytics ("Ascend") and Verdant Associates ("Verdant") (combined "the Ascend team") to provide an independent review of the 2020 Integrated Resource Plans ("IRPs") filed by Arizona Public Service ("APS"), Tucson Electric Power ("TEP") and UNS Electric ("UNSE") (together referred to as load serving entities "LSEs" or "Utilities"). Additionally, the ACC asked the Ascend team to work with the LSEs to develop cost estimates for adopting the proposed Energy Rules versus a hypothetical "least-cost" pathway.

ES. 1 RESULTS OF ENERGY RULES VERSUS LEAST COST ANALYSIS

The Ascend team worked with each utility to develop expansion plans through 2050 in order to calculate the cost impacts of complying with the proposed Energy Rules. The Energy Rules initially required a 100% reduction in greenhouse gas ("GHG") emissions by 2050. Subsequent action by the ACC reduced the requirement to 80% by 2050 and 100% by 2070. The utilities modeled the following cases through 2050.

- 80% clean energy by 2050
- 100% clean energy by 2050
- "Least-cost" portfolio through 2050

The 2020 IRPs modeled their power systems only through 2035, therefore Ascend worked with each utility to develop expansion plans through 2050 that met the GHG reduction requirements of the Energy Rules. By necessity of the short time allotted for this analysis, the utilities developed expansion plans with their IRP portfolios as a starting point. Only minor modifications were necessary to the TEP and APS expansion plans because their IRP plans put them on track to meet the Energy Rules already. The "least-cost" portfolio was assumed to be one in which natural gas generation remained the primary resource for incremental capacity albeit with additional renewable energy added to the system to cover much of the additional energy needs. None of the expansion plans were developed using capacity expansion algorithms but were instead "hand-designed." Regardless of whether these portfolios could be more "optimal," they are directionally instructive as to some of the cost tradeoffs between a more traditional capacity expansion approach and a decarbonization pathway.

In addition to the core cases, the utilities ran sensitivity cases using Ascend's inputs for power and gas prices as well as Ascend assumptions on effective load carrying capabilities of renewables and storage, for a total of six runs each. All modeling was performed in the utility's licensed production cost model Aurora by Energy Exemplar by the utilities themselves rather than by Ascend Analytics. At the time of this report writing, the UNSE analysis remains ongoing. Ascend will file a supplemental report showing the results of that analysis.

Results

Ascend used the modeling results to calculate differences in revenue requirements (cost of supply to serve load and incremental transmission revenue requirements), average rate impacts (revenue requirements divided by retail sales), and average monthly residential bill impacts (rate impacts multiplied by average monthly energy consumption). Table ES -1a, b and c show the results of the analysis for APS:

ES-1a: Revenue Requirements ($M)

	2025	2030	2035	2040	2050
100% Clean	2,714 - 2,865	3,419 - 3,472	3,831 - 3,969	4,294 - 4,738	7,342 - 7,952
80% Clean	2,714 - 2,865	3,419 - 3,472	3,832 - 3,969	3,919 - 4,410	5,657 - 6,193
Least Cost	2,613 - 2,796	3,118 - 3,164	3,272 - 3,436	3,307 - 3,789	4,650 - 5,545
Difference (100% Clean – Least Cost)	69 - 100	301 - 308	533 - 560	949 - 987	2,407 - 2,692
Difference (80% Clean – Least Cost)	69 - 100	301 - 308	533 - 560	612 - 621	648 - 1,008
% Difference (100% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	25% - 30%	43% - 58%
% Difference (80% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	16% - 19%	12% - 22%

ES-1b: Average Rate Impacts ($/kWh)

	2025	2030	2035	2040	2050
100% Clean	0.079 - 0.083	0.088 - 0.090	0.091 - 0.094	0.094 - 0.104	0.136 - 0.147
80% Clean	0.079 - 0.083	0.088 - 0.090	0.091 - 0.094	0.086 - 0.097	0.105 - 0.115
Least Cost	0.074 - 0.079	0.077 - 0.078	0.073 - 0.077	0.067 - 0.077	0.076 - 0.091
Difference (100% Clean – Least Cost)	0.0036 - 0.0044	0.0109 - 0.0111	0.0175 - 0.0179	0.0273 - 0.0274	0.0563 - 0.0597
Difference (80% Clean – Least Cost)	0.0036 - 0.0044	0.0109 - 0.0111	0.0175 - 0.0179	0.0191 - 0.0202	0.0237 - 0.0285
% Difference (100% Clean – Least Cost)	5% - 6%	14% - 15%	23% - 25%	36% - 41%	62% - 78%
% Difference (80% Clean – Least Cost)	6% - 7%	14% - 15%	23% - 24%	26% - 41%	26% - 74%

ES-1c: Average Monthly Residential Bill Impacts ($)

	2025	2030	2035	2040	2050
100% Clean	82.51 - 87.11	92.62 - 94.07	95.74 - 99.18	98.91 - 109.13	142.66 - 154.52
80% Clean	82.51 - 87.11	92.62 - 94.07	95.75 - 99.18	90.28 - 101.59	109.93 - 120.34
Least Cost	77.93 - 83.36	81.20 - 82.41	76.91 - 80.77	70.19 - 80.41	80.00 - 95.40
Difference (100% Clean – Least Cost)	3.75 - 4.58	11.42 - 11.66	18.41 - 18.83	28.72 - 28.73	59.12 - 62.66
Difference (80% Clean – Least Cost)	3.75 - 4.58	11.42 - 11.66	18.41 - 18.84	20.09 - 21.17	24.94 - 29.93
% Difference (100% Clean – Least Cost)	4% - 6%	14% - 15%	23% - 24%	36% - 41%	62% - 78%
% Difference (80% Clean – Least Cost)	4% - 6%	14% - 15%	23% - 24%	26% - 29%	26% - 37%

Table ES – 2a, b, and c show the results of the analysis for TEP:

ES-2a: Revenue Requirements ($M)

	2025	2030	2035	2040	2050
100% Clean	1,226 - 1,223	1,410 - 1,484	1,540 - 1,650	1,540 - 2,033	2,067 - 3,085
80% Clean	1,224 - 1,223	1,409 - 1,484	1,540 - 1,650	1,669 - 1,978	1,874 - 2,864
Least Cost	1,224 - 1,223	1,409 - 1,424	1,540 - 1,518	1,669 - 1,779	1,874 - 2,365
Difference (100% Clean – Least Cost)	2 - 0.30	1 - 59.87	1 - 131.63	44 - 254.05	193 - 720.31
Difference (80% Clean – Least Cost)	0 – 0	0 - 59.70	0 - 131.61	18 - 198.81	19 - 498.88
% Difference (100% Clean – Least Cost)	0% - 0%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 0%	4% - 4%	9% - 9%	14% - 11%	30% - 21%

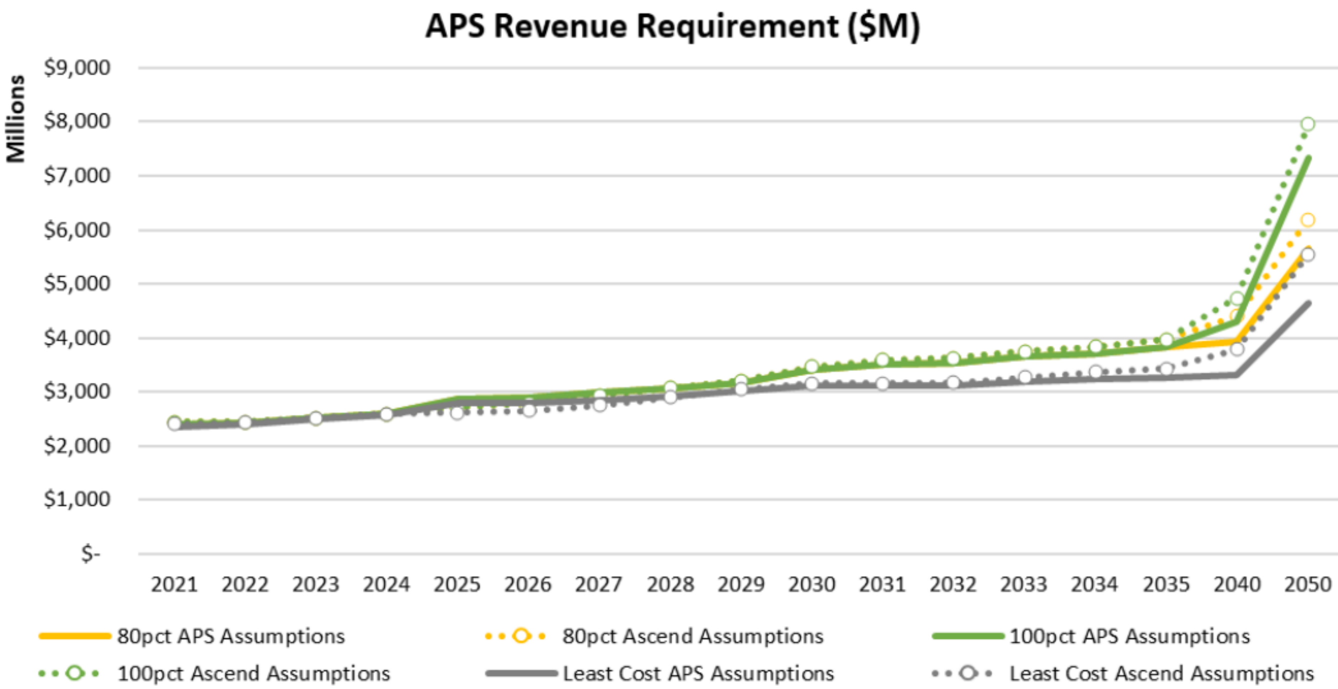
ES-2b: Average Rate Impacts ($/kWh)

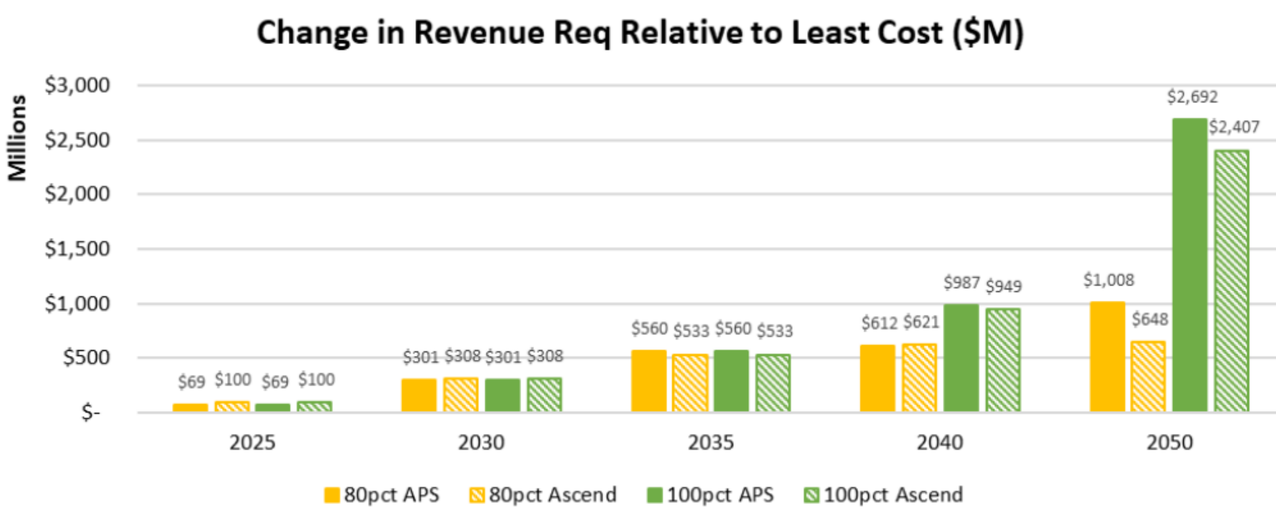
	2025	2030	2035	2040	2050
100% Clean	0.136 - 0.135	0.141 - 0.148	0.145 - 0.155	0.152 - 0.181	0.167 - 0.249
80% Clean	0.13 - 0.135	0.141 - 0.148	0.145 - 0.155	0.150 - 0.176	0.153 - 0.231
Least Cost	0.135 - 0.135	0.141 - 0.142	0.145 - 0.143	0.148 - 0.158	0.152 - 0.191
Difference (100% Clean – Least Cost)	0 - 0	0 - 0.006	0 - 0.012	0.004 - 0.023	0.016 - 0.058
Difference (80% Clean – Least Cost)	0 - 0	0 - 0.006	0 - 0.012	0.002 - 0.018	0.002 - 0.040
% Difference (100% Clean – Least Cost)	0% - 0%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 0%	0% - 4%	0% - 9%	1% - 11%	1% - 21%

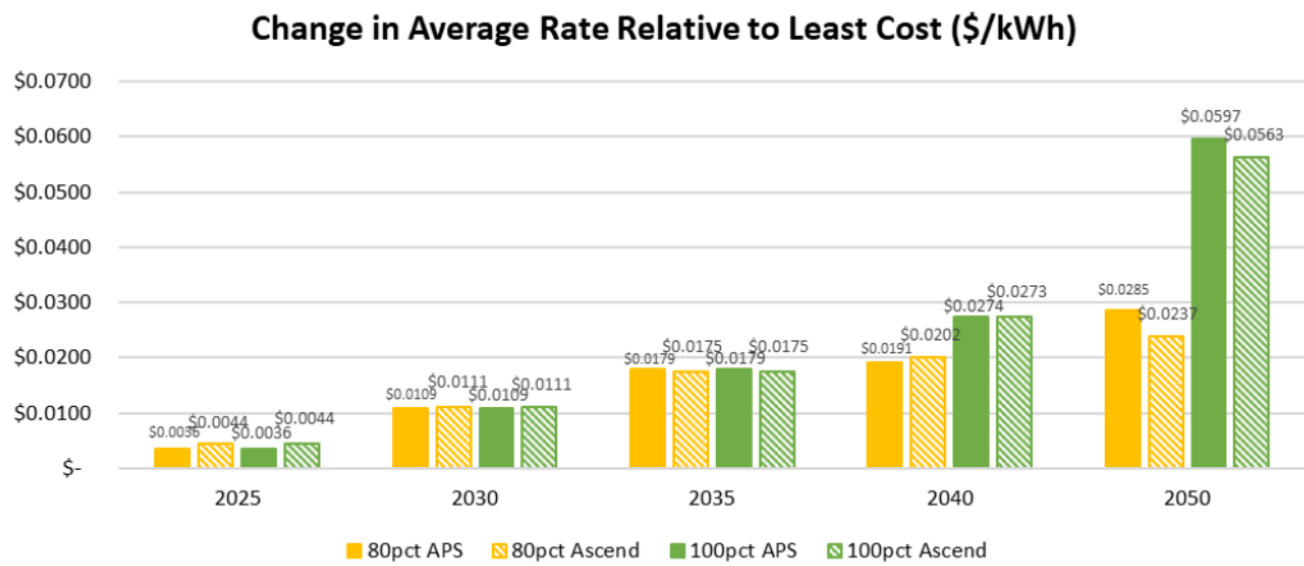
ES-2c: Average Monthly Residential Bill Impacts ($)

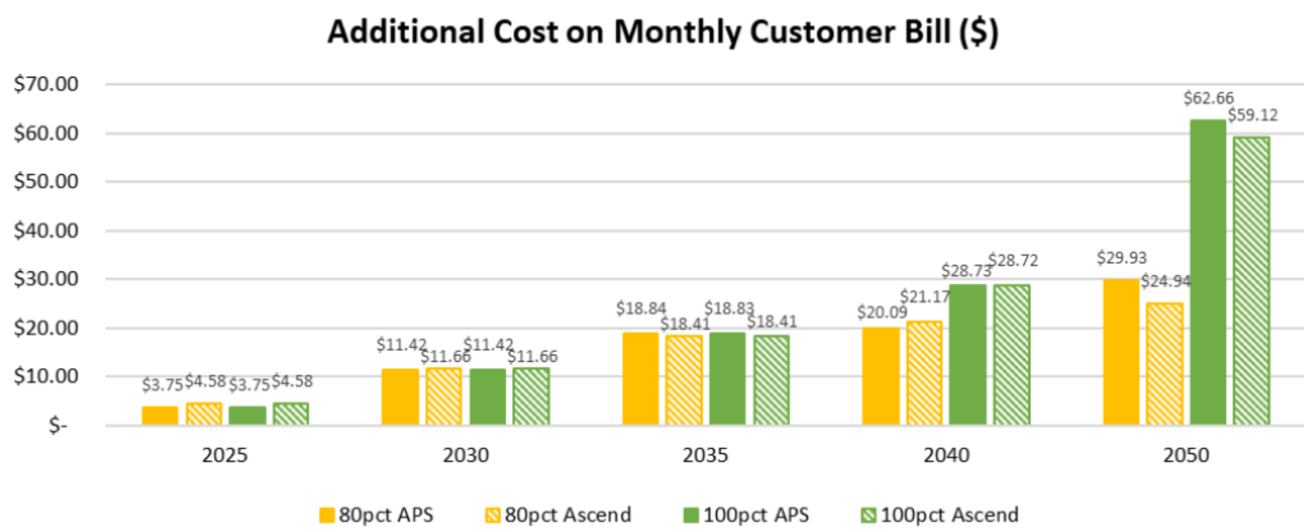
	2025	2030	2035	2040	2050
100% Clean	135.64 - 135.32	140.97 - 148.40	145.09 - 155.40	152.31 - 180.73	167.14 - 249.38
80% Clean	135.42 - 135.29	140.86 - 148.38	145.02 - 155.40	148.41 - 175.82	151.53 - 231.49
Least Cost	135.43 - 135.29	140.86 - 142.41	145.02 - 143.00	148.41 - 158.16	151.53 - 191.15
Difference (100% Clean – Least Cost)	0.21 - 0.03	0.11 - 5.99	0.07 - 12.40	3.90 - 22.57	15.61 - 58.23
Difference (80% Clean – Least Cost)	0 – 0	0 - 5.97	0 - 12.40	1.58 - 17.66	1.56 - 40.33
% Difference (100% Clean – Least Cost)	0% - 0%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 0%	0% - 4%	0% - 9%	1% - 11%	1% - 21%

Note that the revenue requirements and average rates should not be compared between APS and TEP. The revenue requirement for TEP is all-in and includes the costs associated with distribution systems while APS includes only generation and transmission costs. However, distribution costs are considered the same across the different cases and thus the interest lies in the incremental cost relative to the "least cost" scenario. Also, the customer usage assumptions are slightly different between the two utilities causing the average rates to have different base lines.






Change in Average Rate Relative to Least Cost ($/kWh)
$0.0700
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
$0.0036
$0.0044
$0.0036
$0.0044
$0.0109
$0.0111
$0.0109
$0.0111
$0.0179
$0.0175
$0.0179
$0.0175
$0.0191
$0.0202
$0.0274
$0.0273
$0.0285
$0.0237
$0.0597
$0.0563
2025
2030
2035
2040
2050
80pct APS
80pct Ascend
100pct APS
100pct Ascend


Additional Cost on Monthly Customer Bill ($)
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$3.75
$4.58
$3.75
$4.58
$11.42
$11.66
$11.42
$11.66
$18.84
$18.41
$18.83
$18.41
$20.09
$21.17
$28.73
$28.72
$29.93
$24.94
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2035
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2050
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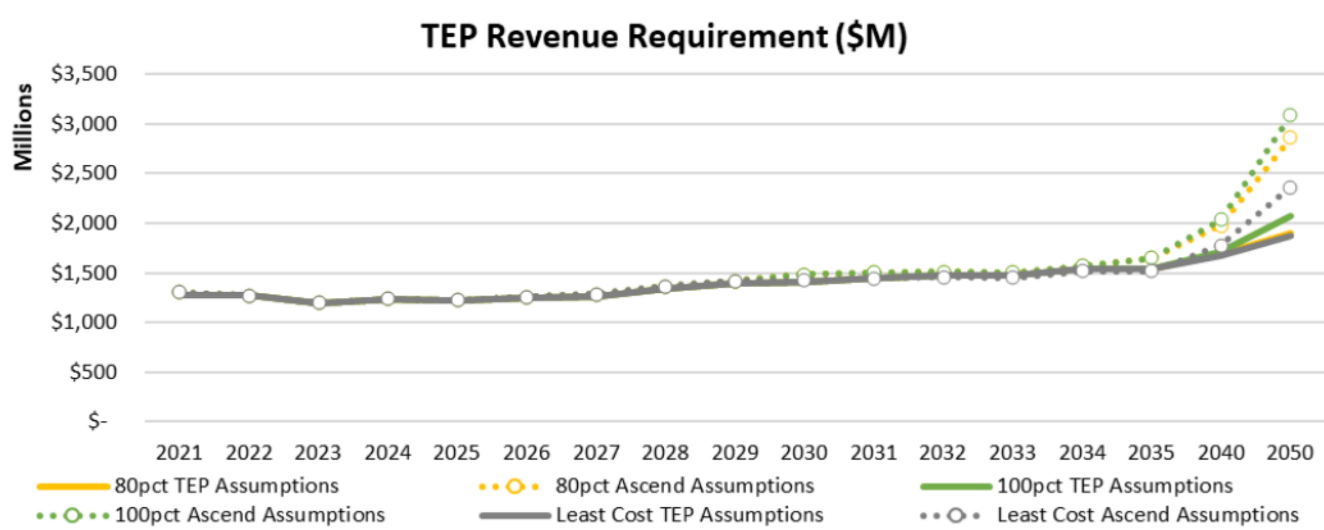
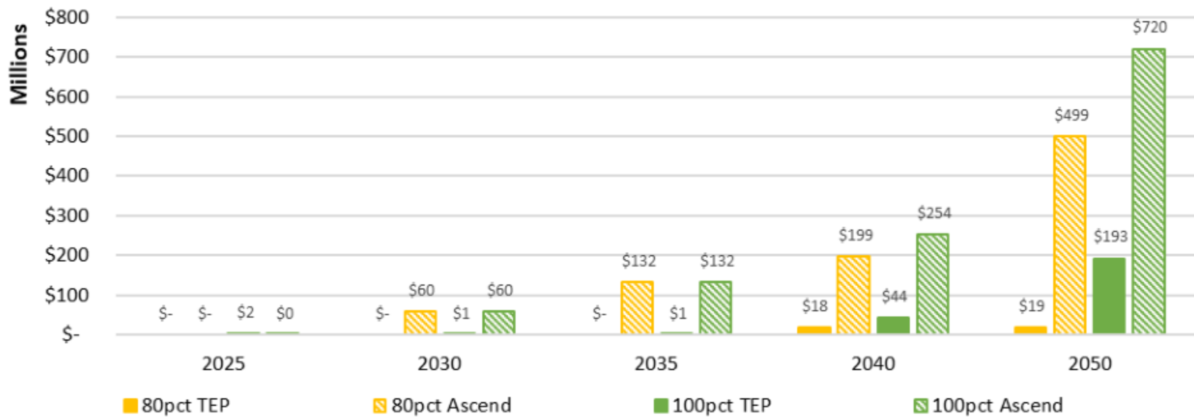
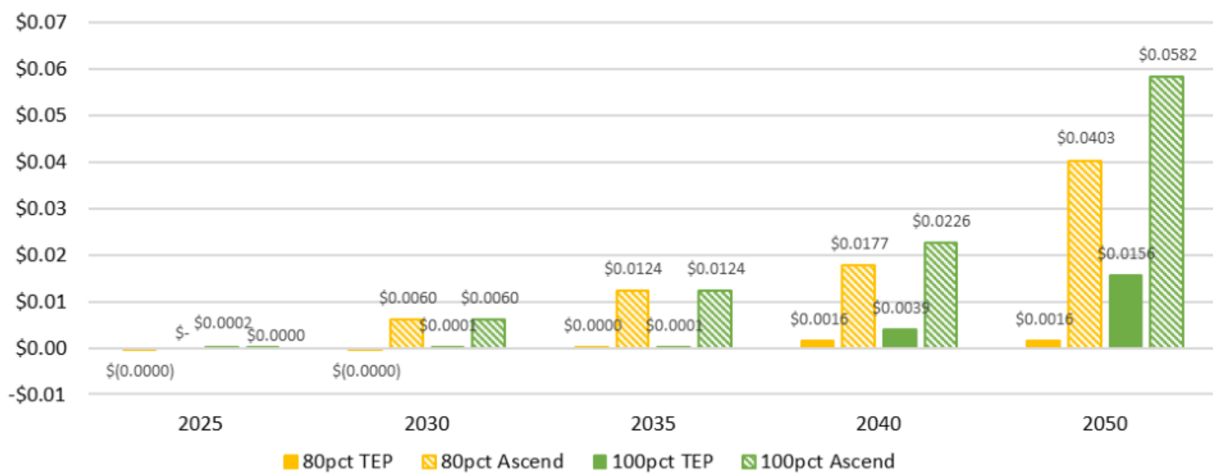
100pct APS
100pct Ascend


TEP Revenue Requirement ($M)
Millions
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$-
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2040
2050
80pct TEP Assumptions
80pct Ascend Assumptions
100pct TEP Assumptions
100pct Ascend Assumptions
Least Cost TEP Assumptions
Least Cost Ascend Assumptions

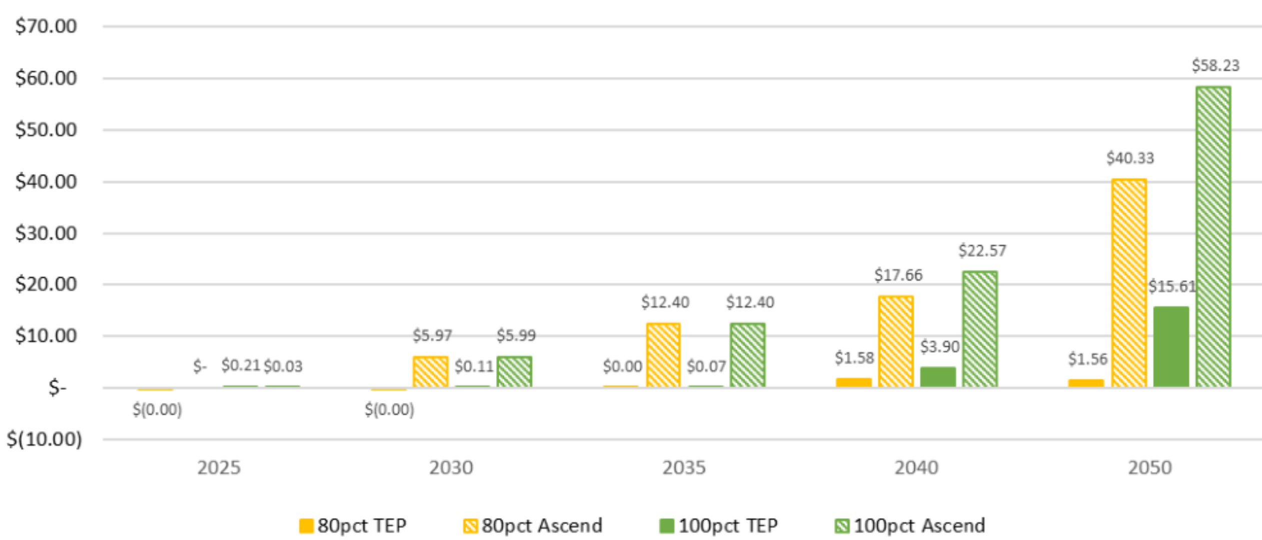
Change in Revenue Req Relative to Least Cost ($M)



Change in Average Rate Relative to Least Cost ($/kWh)



Additional Cost on Monthly Customer Bill ($)



Discussion:

Ascend's key take-aways of the analysis are as follows:

- **The results show low to moderate cost increases in revenue requirements, rates, and bills in both 80% and 100% pathways.**
  - In the APS 80% case, residential customers would pay approximately an additional $18 per month by 2035, between $20 per month by 2040 and $25 - $30 per month in 2050. When going to 100%, these values remain the same through 2035. By 2040 the Energy Rules case would cost an additional $30 per month and an additional $60 per month by 2050. Note that these dollars are nominal. In 2050 dollars, $60 is equivalent to about $30 in today's dollars assuming a 2.5% inflation rate.
  - In the TEP 80% case, residential customers would pay an additional $0 - $12 per month in 2035, $2 - $18 per month by 2040, and $2 - $40 per month by 2050. In the 100% case, by 2035 TEP customers would pay an additional $0 - $12 per month, $4 - $23 per month in 2040, and $16 - $58 per month in 2050.
- The most significant cost increases would occur between the 2040 and 2050 time frame when the utilities achieve between 80 to 100% clean energy. This is due to the need to convert natural gas fired power plants to burn expensive green hydrogen and add longer duration storage (8 to 100 hours) required for capacity and reliability.
- The wider uncertainty band in the TEP results is indicative of differing assumptions on the load carrying capability of renewables and storage. Ascend predicts a faster decline in the ability of solar, wind, and 4-hour storage to provide system reliability than TEP, therefore the Ascend assumptions for TEP's portfolios includes additional capacity and additional cost. TEP also has more aggressive assumptions for decline in clean energy technology costs than what is published in the NREL ATB database.
- Achieving at least 80% clean energy can be reliable and cost-effective with today's technology costs and capabilities. Cost-effectively achieving higher than 80% clean energy while maintaining reliability requires innovation in clean energy technologies, such as green hydrogen, long-duration storage, or advanced nuclear.

Study Limitations

As with any very long-range study, results in the distant future must be taken somewhat with a grain of salt. We have little information as to what technologies will be available or how exactly the power system will evolve. We believe these results are directionally consistent with an emerging consensus[1] that decarbonizing the power sector until at least 80% - 90% clean energy is achievable and cost-effective with today's technology over a timespan covering the next two decades.

Some limitations include:

[1] For example see NREL study on reaching 100% clean electricity https://www.nrel.gov/news/program/2021/the-challenge-of-the-last-few-percent-quantifying-the-costs-and-emissions-benefits-of-100-renewables.html

- The studies only compare three discrete scenarios, none of which were optimized. A more thorough study would leverage capacity expansion algorithms as well as discrete sensitivities to test key assumptions.
- This study was not paired with loss of load probability analysis. We cannot say with confidence that these portfolios are reliable without conducting an independent reliability analysis.
- This study was performed deterministically, meaning we do not analytically capture meaningful uncertainty driven by weather as a fundamental driver of load, renewable output, forced outages, and gas and power price dynamics. A deterministic result only shows a single view of the world versus a distribution of possible outcomes.
- Study is completed with perfect foresight (i.e. model "sees" all prices and optimizes dispatch perfectly) at the hourly level (as opposed to 5-minute intervals), which fundamentally undervalues flexible resources such as batteries in the context of participation in the Western Energy Imbalance Market ("EIM").

Analytical studies such as this one, provide important insights into the mechanics of complex systems including how changes in assumptions about future uncertainties would impact the outcomes. The following table highlights key assumptions and how results would be affected if they were more or less than we believe today.

Table ES – 3: Understanding the Impacts of Key Uncertainties

Assumption	What would cause costs to be less than expected?	What would cause costs to be more than expected?
Effective load carrying capability (ELCC)	ELCC of wind, solar, and batteries are more than we expect, potentially as a function of portfolio effects and geographic diversity.	ELCC of wind, solar, and batteries are less than we expect, potentially as a function of strong correlation in weather regimes on renewable output.
Technology types and costs	If innovation makes storage dramatically more cost-effective than we expect costs of decarbonization would decrease.	If future technologies do not decline as we expect, then costs to decarbonize would be higher than shown here.
Climate change	Climate impacts are more moderate than we expect, meaning less need to build peaking capacity for heat storms.	Climate impacts are worse than we expect, therefore additional capacity is needed to maintain reliability during more frequent and longer heat storms.
Market structure	If LSEs join a regional RTO, the cost of decarbonization due to better coordination of resources across the West.	Not applicable.
Transmission	Federal spending and permitting reforms support additional transmission that unlocks more low-cost renewable energy. Higher adoption and targeted deployment of distribution sited storage and distributed energy resources reduces the need for transmission spending.	No federal spending or permitting reform. Low adoption/sub-optimal deployment of distributed energy resources.

Recommendations on Next Steps

Should the ACC feel more analysis would be beneficial to support regulatory policy making, Ascend makes the following recommendations:

1. Commission a study using an independent analytical firm (and/or national lab, ASU, etc.) to model pathways to 100% clean energy by 2050.
2. Make sure to hire an analyst that uses best-in-class "HD PCMs." There are several that have been developed by various modeling firms.
3. Include other sectors in the analysis, such as transportation and building electrification.
4. Investigate both supply and demand-side solutions.
5. Utilize capacity expansion and scenario design.
6. Include a stakeholder engagement process.
7. Make sure to include reliability analysis, resiliency, and climate impacts.
8. Allot a sufficient amount of time and resources to make the analysis robust and meaningful. Nine months to one year is typical.

ES. 2 REVIEWS OF IRPS AND SUMMARY OF RECOMMENDATIONS FOR FUTURE IRPS

Overall, Ascend commends the LSEs on their IRP work, as they show credible pathways towards a dramatically lower carbon future while also maintaining reliability and managing costs. While there is still room for improvement, the quality of analysis and the boldness of vision is substantially improved from past IRPs. The IRPs show a transition from traditional coal and gas-based resources towards a more flexible cleaner portfolio anchored by renewables and storage.

In Section 2, we review compliance of the IRPs with Decision No. 76632, which directed the LSEs to include in their IRPs several elements such as natural gas storage, battery storage, low or no-load growth, only 20% additional thermal resources, and clean energy portfolios. The LSEs are largely compliant with this Decision, although the treatment of some of these topics could have been more in depth and we recommend further analysis in subsequent IRPs.

Section 3 provides a critical review of the IRPs with respect to modern planning principles, including reliability, equity, environmental performance, and minimizing cost. We also review the quality of the analytical work and recommend several improvements that can be made to enhance their analysis with "high-definition" production cost and reliability modeling. Regarding the IRPs overall, Ascend's full set of recommendations are as follows:

1. IRP Process

a) Develop increasingly more inclusive, open, and transparent stakeholder processes.
b) Include environmental and economic justice analysis as well as voices previously underrepresented in IRP stakeholder processes.

2. Resource Adequacy and Resiliency

a) Include deeper and more robust analysis of resource adequacy with high renewables and storage.
b) Include analysis of interconnected system risks between the gas and power systems.

c) Model correlations between weather and each of renewable generator output, forced outage rates, and transmission capacity.
d) Include analysis of climate impacts on future system reliability.

3. Resource Selection

a) Leverage optimized capacity expansion algorithms combined with "hand designed" portfolios and sensitivities.
b) Research and report out additional information on the uses for and economics around green hydrogen or other clean fuels, and how the existing gas thermal fleet could be repurposed to burn these fuels.
c) Include more research and modeling of non-lithium ion storage options and long-duration storage.

4. Demand Side Management (DSM)

a) Explore options for flexible demand through technologies such as smart thermostats, vehicle-to-grid, behind-the-meter solar and storage, and others on a level playing field with traditional supply side options.
b) Model linkages between electricity provision and building and vehicle electrification as a decarbonization strategy.
c) Incorporate more analysis of interval data for all demand side resources to better understand how their effects might shift demand impacts.
d) Include more scenario analysis, particularly for sources of load with high uncertainly (i.e. electric vehicles).

5. Modeling Enhancements

a) Incorporate weather as a fundamental driver of power system operations and value.
b) Transition away from a "dispatch-to-load" concept towards one that incorporates further integration into Western energy markets. Incorporate hourly and sub-hourly prices from the Western Energy Imbalance Market and a future Extended Day Ahead Mechanism.
c) Run stochastic studies to capture sensitivity to variations in weather, generation, and prices. Quantifying uncertainty is essential for risk management, portfolio balancing, and system reliability.
d) Assure long-term power price forecasts are aligned with changing market dynamics driven by renewable energy and storage deployment.

<u>Chairwoman's Letter on "Must-Run" designation for Four Corners and Solana PPA</u>

Section 3.3.3 shows a response to the ACC Chairwoman's letter dated July 27, 2021. In it we find the following conclusions regarding the "must-run" status of Four Corners and Solana:

- APS should have explicitly shown a scenario in which Four Corners retired earlier than 2031. We do not know if retiring Four Corners early would be least-cost without model runs of that option. Regardless of whether it is the "least-cost" pathway, APS believes that an earlier retirement would be risky from a system reliability perspective and would be difficult to terminate the coal contract prior to expiration in 2031 because it would require agreement from all owners of the plant. These concerns and difficulties are valid, nonetheless with many stakeholders interested in understanding the options around early retirement, APS could have explicitly shown this scenario and analytically demonstrated with loss of load probability studies as well as qualitative reasoning why this would not be an acceptable or prudent option at this time.

- The Solana power purchase agreement is a contract for offtake of renewable energy from the Solana concentrating solar generation station. The contract was approved in 2008 prior to a rapid decrease in the cost of solar photovoltaic technology. APS only pays for energy delivered even if that energy costs significantly above market. While in hindsight the contract appears to be a bad deal for APS ratepayers, we can only judge decisions based on the information known at the time. From a modeling perspective, the contract should be considered "must-take" because it is a renewable PPA with no fuel cost and APS is contractually obligated to take the energy as it is generated.

1 Introduction

The Arizona Corporation Commission (ACC or "Commission) engaged Ascend Analytics (Ascend) and Verdant Associates (Verdant) (combined "the Ascend team") to provide an independent review of the 2020 Integrated Resource Plans (IRPs) filed by the three regulated utilities (together referred to as load serving entities or "LSEs"). Additionally, the ACC asked the Ascend team to work with the LSEs to develop cost estimates for adopting the proposed Energy Rules versus a hypothetical "least-cost" pathway.

Ascend, a leading energy modeling software and consulting services firm based in Boulder Colorado, is focused on developing and leveraging powerful analytics solutions for use in modern resource planning and decision analysis amidst a rapidly changing energy system. Based in Berkeley, California, Verdant is home to leading experts in the fields of demand-side energy resources such as energy efficiency, demand response, and distributed energy resources as well as load forecasting.

This report summarizes our findings. It includes:

- A review of the compliance with Commission Decision 76632 (Section 2)
- A review of the IRPs with respect to assumptions and inputs as well as industry best modeling practices (Section 3)
- A modeling exercise executed in partnership with the LSEs to quantify costs of compliance with the new proposed energy rules relative to a least-cost case (Section 4)

1.1 REGULATORY BACKGROUND

The ACC's Resource Planning and Procurement Rules ("IRP Rules") were adopted on February 3, 1989, and amended by final rulemaking, effective December 20, 2010. The IRP Rules can be found in Arizona Administrative Code Title 14 Chapter 2 Article 7 Resource Planning and Procurement.1 *A.A.C. R14-2-701 through R14-2-706.* The 2010 amendment updated the original IRP rules to include the environmental impacts of resources and procurement costs.

The IRP Rules require that 15-year IRPs be prepared and submitted by LSEs to the Commission in each evenly numbered year on April 1. The IRP Rules define a "load-serving entity" as "...a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with a capacity of at least 50 megawatts combined."

The following Commission regulated electric utilities are classified as LSEs:

- Arizona Public Service Company ("APS"),
- Tucson Electric Power Company ("TEP"),
- UNS Electric, Inc. ("UNS Electric"), and
- Arizona Electric Power Cooperative ("AEPCO").

Pursuant to A.A.C. R14-2-704(A), Commission Utilities Division Staff ("Staff') is required to docket a report ("Staff Report") that contains its analysis and conclusions of the IRPs. In the Staff Report, Staff will assess the compliance of each IRP with the LSE Reporting Requirements contained in A.A.C R14-2-703(C), (D), (E), (F), and (H), and the eleven factors listed under A.A.C. R14-2-704(B). The Staff Report is filed for the Commission's consideration. The IRP Rules require a determination by the Commission whether each IRP filed by the load serving entities complies with the requirements of the IRP Rules. The Commission votes to acknowledge or not acknowledge the plans.

On March 29, 2018, the Commission issued Decision No. 76632 which addressed Commission Staff's assessment of the adequacy of the 2015-2016 IRPs for the aforementioned regulated utilities. In Decision No. 76632, the Commission issued an order that declined to acknowledge the IRPs filed by APS, TEP, and UNS Electric. The Commission adopted a new 3-year timeline for each LSE to follow in preparing and filing the next IRPs.

Commission Decision No. 76632 also states:

> "It is further ordered that for all future IRPs submitted by Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., Staff shall, in addition to their existing review requirements and methods, hire one or more third-party analysts to conduct an independent review of the scenarios and portfolios presented in each IRP, and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. The hiring of a third-party analyst shall require prior Commission approval."

Commission Decision No. 76632

Commission Decision No. 76632 specifies additional requirements for each of the Load-Serving Entities' IRPs. The following are relevant ordering paragraphs from the decision:

Table 1: Requirements of Decision 76632

Topic	Requirement
Natural Gas Storage	…Load Serving Entities, except Arizona Electric Power Cooperative, **shall address natural gas storage in greater detail in future IRPs**, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus, a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, shall be a cornerstone of utility resource planning in Arizona. Consequently, the Load Serving Entities, except Arizona Electric Cooperative, **shall include a wide variety of natural gas price scenarios in future IRPs.**
Storage technologies	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include, in future Integrated Resource Plans, an analysis of a reasonable range of storage technologies and chemistries; and an analysis of anticipated future energy storage cost declines as further discussed in Decision No. 76295.
Storage and non-wires alternatives	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include a storage alternative as a resource option in future Integrated Resource Plans, and shall include an analysis of storage alternatives into their respective processes when considering upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resources.

Load growth justification report for APS	IT IS FURTHER ORDERED that Arizona Public Service Company shall prepare a report justifying its 2015 and 2016 IRP load growth projections. Said report shall also include an analysis of (A) a "no growth" scenario; and (B) a "low growth" scenario (<1-percent growth) and the resultant implications on APS's resource selections under each scenario. APS shall also include a discussion regarding how each of the required scenarios affect its Three Year Action Plan. Said report shall be filed in the instant docket within 90 days of the Commission's decision in this matter.
No growth and low load growth scenarios	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include "no-growth" and "low-growth (<1%)" scenarios in future Integrated Resource Plans, until further order of the Commission
Thermal as no more than 20% of new resource additions. Tribal Nations	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. in each of their next IRPs shall analyze, along with their preferred portfolio, at **least one portfolio where the addition of fossil fuel resources is no more than twenty percent (20%) of all the resource additions**. In developing each of their portfolios to satisfy this requirement, Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each work in good faith with each of the stakeholders [and] to continue to **participate and also work in good faith with any Tribal Nations located in Arizona** that desire to participate in developing the portfolio to satisfy this requirement.
Clean Energy Portfolio Analysis	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., in each of their next IRPs shall analyze, along with their preferred portfolio, at least one portfolio that includes, as a Fifteen year forecast, all of the following: **the lesser of 1000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20% of system demand, at least 50% of "clean energy resources," which are resources that operate with zero net emissions beyond that of steam, of which 25 MW of nameplate capacity running at no less than 60% capacity factor are renewable biomass resources; and at least 20% of Demand Side Management.**

2 Review of Compliance with Decision 76632

This section provides an independent review of each LSE's IRP with respect to the requirements of 76632.

2.1 APS COMPLIANCE WITH 76632

Natural Gas Storage and Future Natural Gas Price Paths

APS included a short discussion on the prospects of natural gas storage in Arizona. In recent years, Kinder Morgan proposed building a salt dome natural gas storage facility near Eloy, Arizona. The proposed project would store up to 4 billion cubic feet (Bcf) of natural gas. While a storage facility would offer enhanced reliability in the case of a pipeline rupture, the project failed to gain interest from Arizona utilities and is now delayed indefinitely. There are no other natural gas storage projects being considered in Arizona. APS will continue to monitor developments in natural gas storage options.

Given the current situation in Arizona for natural gas storage, APS spent little effort researching how natural gas storage may assist their operations. The situation on the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions, we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers.

The second part of the natural gas modeling requirement is to include a wide variety of natural gas price scenarios. APS performed sensitivity analysis on the natural gas price forecast in the production cost model with a low, base, and high natural gas price forecast. The three cases were based on projections from the EIA in the 2020 Annual Energy Outlook. APS found the model outputs were not sensitive to the natural gas price forecast in the model. This is because natural gas generation contributes between 5.5% and 16.7% of the total portfolio energy in 2035, depending on the portfolio. When modeling future states of gas prices, the secular trend (i.e. growth rates) are not as important as understanding power system economics during short periods of scarcity and price spikes, such as what happened to natural gas markets in February 2021 or previous polar vortex events. A simulation-based modeling approach to capture these tail events is recommended.

Finally, policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization.

Storage technologies

Energy storage is considered an essential tool for APS to meet the aggressive renewable energy targets. APS's action plan includes adding 750 MW of energy storage by 2024 and 850 MW by 2025. This amount of battery energy storage was included in all portfolios modeled in the IRP, except for the least-cost baseline. From 2025 to 2035, the three portfolios analyzed by APS ("bridge", "shift", and "accelerate"), add from 4,100 MW to 9,800 MW of battery energy storage. Half of the battery additions are part of solar hybrid installations. All of the batteries have a four-hour duration.

While APS described a wide range of storage technologies other than lithium-ion, such as flow batteries, pumped hydro, CAES, and flywheels none of these were included in the three portfolios. The cost of Li-Ion batteries for 4-hour duration applications has plummeted over the last decade and is expected to fall further. As need for longer duration storage arises in the future (8-hour to 100+ hours), these emerging technologies should be evaluated in more detail.

APS should consider further analysis to determine the most effective schedule for energy storage deployments over a range of scenarios and cost projections. Capacity expansion modeling, resource adequacy analysis, and production cost modeling with sub-hourly dispatch would fully capture the costs and benefits of energy storage technology over time and help APS select the optimal storage deployment pathway.

Storage and non-wires alternatives

APS states on the first page of Chapter 4 that it considers non-wires alternatives to address the challenges associated with changing resource types and high population growth. Aside from this mention, there is no further explicit discussion of non-wires alternatives. It is not clear if non-wires alternatives were considered during the planning process for the 2020 – 2029 transmission plan that APS filed prior to the IRP. Based on the IRP documents, it appears that APS did not give significant consideration for non-wires alternatives like storage and targeted DSM programs. APS has expressed to the Ascend team that storage in the IRP could be installed either as transmission or distribution level assets, both of which would help manage and defer costs associated with additional transmission and distribution level capital spending on traditional utilities investments such as increased capacity, reconductoring, sub-station upgrades, etc.

In future IRPs, APS should include analysis on specific non-wires alternatives considered in the planning process. The analysis should include cost savings associated with non-wires alternatives due to the avoided or postponed transmission costs. APS should evaluate how new non-traditional options such as targeted demand response and storage competes against traditional utility capital investments in transmission and generation.

Load growth justification report for APS

APS provided substantial discussion and analysis supporting the load growth forecast used in the modeling. Itron, a leading load forecasting firm, was retained to review the APS load forecast. The Itron report was included as Appendix E of the IRP document.

Chapter 5 of the IRP describes the APS load forecast, including that their original load forecasting approach was consistent with industry practices while noting that Itron believed that APS should revisit the residential model. APS adjusted the residential model specification consistent with Itron's recommendations. The IRP load forecast describes the expected growth in energy and demand under base, low growth rate, and no growth scenarios. They present energy growth forecasts for residential, C&I, EVs, and data centers. The IRP describes how the average residential usage per customer and the C&I usage per square foot (intensity) for existing customers is forecasted to decline due to the impacts of distributed generation (DG) and demand-side management (DSM), but the sector level usage will grow due to population and business growth. Chapter 5 also describes the past and projected future growth in Arizona's population, forecasting the future growth will not slow as it did following the 2008 recession and it will not accelerate to grow as fast as it did in the 1990s. The chapter describes the increasing interest in DSM and DG and their impact on customer energy usage, their impact on the timing of the system peak and how rooftop solar has only minor impact on the estimated level of the peak. Chapter 5 also describes how growth in data centers and EVs will impact the electric and demand forecasts from 2020 to 2030.

Confidence in APS's forecast of future load growth is strengthened by their process of reaching out to third parties to review and comment on the forecast's models and DSM and DG growth components. APS's response to Itron's suggestions to update their residential forecasts illustrates APS's desire to critically review their approach and make the necessary updates. The ongoing development of tools designed to forecast future DSM and electric vehicles (EV) growth also indicates the importance of these transformative technologies in future load growth.

Ongoing updates to the forecasts of DSM, DG, distributed storage, and EV will be necessary to maintain a firm understanding of how these technologies are impacting future energy and demand growth. Growth in these technologies, and how the technologies are used (timing of EV charging and charge and discharge of distributed storage), can have large impacts on energy and demand growth.

Pulling the forecast of data center growth out from the general C&I load forecast helps to improve the general understanding of the C&I and the data center forecast. This approach should be maintained.

Itron's review of APS's load forecast stated that the forecasts assume that DSM and DG do not decay. APS's DSM programs incorporate behavioral programs with very short persistence and existing distributed solar production decays at a rate of 1% to 1.5% per year. If behavioral DSM and DG maintain their importance within the APS load forecast, careful review of the no decay assumption is warranted.

No growth and low load growth scenarios

As directed, APS performed sensitivity analysis on the portfolios to include a no growth and a low growth of 0.9% annually for customer load. The base case load growth was estimated to be 2.1% annually. The results are summarized in Table 7-11 on page 154 of their IRP. The range of load growth modeled (0 to 2.1% annual growth) has a significant effect on the revenue requirement (11% difference), the capital expenditures (88% difference), the share of clean energy serving load (7% difference), and the amount of renewable curtailment (45% difference). Other variables shown have relatively small changes in output values for the range of load growth scenarios.

APS followed the directive in performing the load growth sensitivity analysis. There was no consideration for a high load growth future. This may have been a result of assuming a 2.1% growth in the base case which is high compared to most places in the country.

Future IRPs should evaluate an "electrify everything" pathway, which would imagine a near total transition to electrified transportation and building sector. Load growth could also be higher than expected due to climate driven increases in average temperature and more frequent extreme heat waves.

Thermal as no more than 20% of new resource additions. Tribal Nations

The three portfolios assembled for the IRP analysis limit thermal to less than 20% of new resource additions. The "Bridge" portfolio has an added natural gas capacity slightly less than 20%, "Shift" has more aggressive reductions, and "Accelerate" has zero added thermal capacity. The natural gas capacity included in the modeling is assumed to be able to be converted to hydrogen at a future date. Additionally, all portfolios include retiring the 1,357 MW of coal from Four Corners and Cholla.

The coal retirements have an important consequence for the Tribal communities. Equity issues were not specifically discussed in the IRP document, but APS attempts to address equity issues for communities affected by the retirements with enhanced DSM offerings. The excerpt below was taken from a data response from APS explaining their initiative to address equity.

"APS recognizes the important role coal plants play in the local communities and has addressed equity issues in its current rate case (Docket E-01345A-19-0236). Please see the rebuttal and rejoinder testimonies on Coal Community Transition (CCT) of APS witness Barbara Lockwood for details.

APS addressed equity issues extensively with the DSM planning process. Equity is a strong consideration in DSM including special program offerings and set asides for renters, limited income, schools, non-profits, and small businesses. In addition, APS also launched a new Tribal Communities Energy Efficiency program that is targeted to provide energy efficiency rebates and services exclusively to Hopi and Navajo tribal communities in Northern Arizona impacted by coal plant closures. This program was initiated by the Commission in recognition of important equity considerations associated with the impacts of coal plant closures in these communities. "

In future IRPs, APS should provide more analysis showing how much natural gas/hydrogen capacity is needed to maintain reliability. Detailed reliability analysis should provide more insight into the portfolio need for flexible capacity to manage the high level of renewables. Additionally, APS should provide an economic assessment of converting natural gas to hydrogen or other green fuels such as ammonia or renewable natural gas. The current IRP could have been improved with a more robust analysis of hydrogen conversions.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder engagement and feedback.

Clean energy portfolio analysis

All three of the portfolios exceed the 50% clean energy goal by 2035. The energy mix in 2035 ranges from 79% clean energy to 91% clean energy. The largest contributions come from renewables (mainly solar) and nuclear. The "Accelerate" portfolio covers the requirement of 25 MW of biomass. APS is planning to install 850 MW of battery storage (four-hour duration) by 2025. APS shows that they meet the clean energy portfolio requirement of Decision 76632.

The portfolios analyzed in the IRP were designed by hand. Ascend recommends APS incorporate both capacity expansion modeling and hand designed portfolios to meet various clean energy targets. This would allow APS to optimize resource costs for various clean energy targets.

2.2 TEP COMPLIANCE WITH 76632

Natural Gas Storage

TEP discusses natural gas storage in Chapter 8 of its IRP. The discussion points out that there are no natural gas storage facilities in the state of Arizona and that an investment in natural gas storage would require joint participation with other utilities and depend on both gas storage economics and the degree to which natural gas is being used as a fuel in TEP's portfolio. Additionally, the IRP includes a spread of portfolio costs that reflect a variety of gas future conditions and stochastic gas price simulations, shown in charts 32, 35 and 36. A high degree of correlation between gas and power prices were held, but these did not include associated correlations with load or renewable generation.

The TEP IRP argues that the case for gas storage should be dependent on a coordinated regional effort. However, the discussion of comparative economics with other storage technologies should be clarified, given that energy storage options vary greatly in their durations, and by extension, in the reliability challenges that they address.

Overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution.

Storage technologies

TEP discusses storage technologies in Chapter 10 of its IRP. The IRP highlights that the vast majority of battery systems are lithium-ion, identifies the lack of technology diversity in storage as a potential risk, and states that TEP will continue to explore newer storage technologies as options emerge. Storage cost forecasts are discussed in Chapter 7, with TEP using the NREL ATB 2019 storage cost followed by relative cost declines from Wood Mackenzie. This forecast results in a decline in nominal capital costs of nearly 40% by 2035. The comparison between storage durations is mainly done on a levelized cost of energy basis which is not an appropriate metric for comparing the cost of energy storage.

The TEP IRP considers future cost declines of storage that are consistent with common forecast sources but does not provide sufficient consideration to alternate storage technologies. This is particularly important given the different cost versus power tradeoffs of different storage technologies, and the corresponding services that they are suited for providing the grid. In addition to lithium ion, storage options that should be considered are flow batteries, liquid air, metal air, hydrogen/renewable fuels, and other emerging technologies.

Overall, the discussion of storage technologies is very brief. Future IRPs should provide a more detailed discussion of the options and applications of storage at different durations, as well as evolution in effective load carrying capabilities as storage penetration increases.

Storage and non-wires alternatives

Each of the TEP IRP portfolios includes significant additions of storage resources. Chapter 4 discusses holistically the future of the distribution grid, and the roles of energy efficiency, demand response, storage, and microgrids. While storage is not specifically discussed as a non-wires alternative, the IRP demonstrates that TEP is paying attention to the evolving nature of the distribution system and is aware of the potential role of storage as a distribution-level resource.

Historically, issues surrounding the distribution grid were not addressed in power supply resource planning. Storage is relatively a new technology that has co-benefits between energy supply and the distribution grid including serving system peak demand and providing various services to the distribution grid such as voltage support, resilience benefits, and traditional infrastructure spending deferral. Future IRPs should continue to discuss the evolution of the distribution grid and include behind-the-meter and distribution-level storage as part of the solution options. NWAs will become more valuable with the consistent increases in peak demand and the limitation of expanding existing transmissions and distribution networks.

No growth and low load growth scenarios

TEP's load growth scenarios are described in Chapter 8 of the IRP, and include base (L1), no growth (L2), low growth (L3), and low and high EV sales (L5 and L6 respectively) load scenarios. The portfolio analyses described in chapter 9 uses the base load forecast, with additional scenarios low and high load scenarios presented in appendix

D. TEP presents additional load growth scenarios for the preferred portfolio in Chapter 10. This discussion includes alternations to the reference portfolio for each of the load forecasts that maintain the same reserves and renewable energy penetration as the base load (L1) scenario.

Thermal as no more than 20% of new resource additions. Tribal Nations

None of the 15 portfolios presented in the TEP IRP include any new thermal resource additions, and thus suggested portfolios all comply with the 20% requirement.

The IRP does not discuss any engagement specifically with tribal nations, though TEP mentions stakeholder workshops in May 2019 and March 2020 and makes frequent reference to stakeholder support and working with stakeholders in designing the portfolios used in the IRP.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder input and feedback.

Clean energy portfolio analysis

Portfolio P05 meets the requirements of Decision 76632. Many other portfolios, including TEP's preferred portfolio, meet the requirements of the Clean Energy Portfolio apart from the inclusion of 25 MW of biomass. Future IRPs would benefit the use of a capacity expansion model to optimize clean energy targets.

2.3 UNSE COMPLIANCE WITH 76632

Natural Gas Storage

UNSE discusses natural gas storage in Chapter 8 of its IRP. The discussion mirrors the TEP IRP, identifying that there are no natural gas storage facilities in the state of Arizona and that an investment in natural gas storage would require joint participation with other utilities and depend on both gas storage economics and the degree to which natural gas is being used as a fuel in UNSE's portfolio. Additionally, the portfolio cost analysis includes a spread that reflect a variety of gas future conditions and stochastic gas price simulations, shown in Charts 18 and 20. Correlations of 90% between gas and power prices were held, but these did not include associated correlations with load or renewable generation.

Like TEP, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional discussion and analysis related to system reliability and the risks/consequences of pipeline distribution.

Storage technologies

UNSE discusses storage technologies in Chapter 9 of its IRP. The IRP highlights that the vast majority of battery systems are lithium-ion, identifies the lack of technology diversity in storage as a potential risk, and states that UNSE will continue to explore newer storage technologies as options emerge. Storage cost forecasts are discussed in Chapter 7, with UNSE using the NREL ATB 2019 storage cost followed by relative cost declines from Wood Mackenzie. This forecast results in a decline in nominal capital costs of nearly 40% by 2035.

The UNSE IRP considers future cost declines of storage that are consistent with common forecast sources but does not provide sufficient consideration to alternate storage technologies. This is particularly important given the different cost versus power tradeoffs of different storage technologies, and the corresponding services that they are suited for providing the grid. In addition to lithium ion, storage options that should be considered flow batteries, liquid air, metal air, hydrogen/renewable fuels, and other emerging technologies.

Overall, the discussion of storage technologies is very brief. Future IRPs should provide a more detailed discussion of the options and applications of storage at different durations, as well as evolution in effective load carrying capability as storage penetration increases.

Storage and non-wires alternatives

Each of the UNSE IRP portfolios includes significant additions of storage resources. Chapter 4 discusses holistically the future of the distribution grid, and the roles of energy efficiency, demand response, storage, and microgrids. While storage is not specifically discussed as a non-wires alternative, the IRP demonstrates that UNSE is paying attention to the evolving nature of the distribution system and is aware of the potential role of storage as a distribution-level resource.

Future IRPs should continue to discuss the evolution of the distribution grid and include behind-the-meter and distribution-level storage as part of the solution options. NWAs will become more valuable with the consistent increases in peak demand and the limitation of expanding existing transmissions and distribution networks.

No growth and low load growth scenarios

UNSE's load growth scenarios are described in Chapter 8 of the IRP, and include base (L1), low growth (L2), no growth (L3), and high growth (L4) load scenarios. The portfolios analyses described in Chapter 9 of the IRP are all for the base load forecast, while sensitivities to the different load growth scenarios are described in Chapter 10. This discussion includes alternations to the reference portfolio for each of the load forecasts that maintain the same reserves and renewable energy penetration as the base load (L1) scenario.

Because UNSE plans to procure resources through all source RFPs and has minimal major capital expenditures into large thermal assets, it has relatively high flexibility in adjusting procurement according to the realized changes in load. As a result, UNSE is largely insensitive to load uncertainty. However, the IRP does not present analysis of the additional costs or savings that would be incurred as a result of procuring for one load future only to have a different one arises. This could be done, for example, by aligning to one load forecast for the beginning of the period, followed by a transition to the other load forecast, and comparing cost differences between portfolios that are developed for one load forecast or the other.

Future IRPs should provide greater discussion of the risks of market dependence, over-procurement, and the portfolio cost sensitivity to inaccurate load forecasts.

Thermal as no more than 20% of new resource additions. Tribal Nations

The portfolios evaluated by UNSE are listed in Chapter 9, Table 18, in its IRP. Portfolios P01a, P02a, P02c, and P03a all have thermals as no more than 20% of the resource additions. Portfolio P02b, the preferred (reference) portfolio, should likely also fit this definition, depending on how energy efficiency is counted as a resource addition, given that P02b has a greater amount of energy efficiency than P02a.

The IRP does not discuss any engagement specifically with tribal nations, though UNSE mentions stakeholder workshops in December 2019 and makes frequent reference to stakeholder support and working with stakeholders in designing all source RFPs for future resource procurement.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder input and feedback.

Clean Energy Portfolio Analysis

UNSE complies with the Clean Energy Portfolio requirement of Decision 76632. The portfolios considered are listed in Table 18 in Chapter 9 of the IRP. Portfolio P01a is stated as meeting the requirements of this order, with 25MW of Biomass, 100MW of storage, and 20% of demand-side management (22% energy efficiency). Additionally, UNSE's preferred portfolio mostly meets this requirement, with the exception of the biomass resources. Future IRPs would benefit the use of a capacity expansion model to optimize clean energy targets.

3 Review of Integrated Resource Plans

The following chapter provides a critical review of the Integrated Resource Plans filed with the ACC in Summer 2020. Section 3.1 discusses the Ascend team's view of how resource planning is changing given the evolution in energy technologies, increases in renewables across the Western grid, and changing expectations of stakeholders. Section 3.2 describes Ascend's approach to this review. Section 3.3 presents the results of Ascend's review for each LSE.

3.1 MODERN RESOURCE PLANNING: A PRIMER

Integrated resources planning is evolving rapidly alongside the seismic shifts in the energy landscape. In the past, planning analysts would develop load forecasts and predict how many baseload (coal, nuclear), mid-merit (natural gas combined cycles) or peakers (natural gas turbines) would be needed. The instructions were simple: maintain system peak reliability while minimizing costs to the ratepayer. Today's planner must balance many more priorities, including balancing and optimizing across the following new principals of resource planning:

- **Maintaining system reliability** – the core foundational mission remains the same: keep the lights on (most) of the time. No power system is built to be reliable 100% of the time, but the "1 day (24 hours) of outage every ten years (87,600 hours) remains the industry standard for peak reliability. However, now the power system must also retain enough flexible capacity to be able to integrate intermittent renewable energy as well as ramp up to meet the evening peak when the sun goes down. Planners must also understand how the future grid can maintain reliability relying on duration limited resources such as battery storage, which today generally discharges for only four hours. Add on top of that the need to plan for more extreme weather like heat waves driven by climate change, which can cause more resource outages, spike up demand, and threaten transmission lines. In short, maintaining reliability is becoming an increasingly difficult challenge.
- **Reducing greenhouse gas emissions to zero by mid-century** – Climate scientists from the Intergovernmental Panel on Climate Change (IPCC) to the National Academy of Sciences and many others have made clear that human civilization must rapidly reduce emissions that cause anthropogenic climate change. To avert the worst consequences, emissions need to drop to zero by mid-century. The electricity sector plays a key role in this transformation, as zero carbon energy technologies such as nuclear, renewables, storage, and clean fuels can be used to power buildings, transportation, and much of industry. Across the country whether driven by state mandates or customer pressure, utilities are strategizing and preparing for a wholesale transition to clean energy.
- **Equity and Environmental Justice** – Planners must understand and incorporate increased stakeholder and societal focus on the negative impacts of fossil fuel environmental pollution disproportionately impacting poor communities and communities of color. At the same time fossil power plant closure has major impacts on the communities in which they provided good paying jobs and tax revenues. A transition to clean energy must provide impacted communities with opportunities to take part in the clean energy economy. Equity and justice in resource planning is a relatively new area of concern but one that is important to address head on and bring in voices that have been historically marginalized in the past.
- **Keeping rates affordable** – Electricity remains a foundational piece of modern human livelihood and utilities must achieve the first three goals while also keeping the cost of electricity affordable for all. If full decarbonization requires a transition of space heating and transportation to electricity,

affordability must be maintained. On the one hand, recent and ongoing advances in technology have made energy efficiency, demand response, renewables, and storage competitive with traditional fossil fuel resources. On the other hand, additional spending on transmission and distribution is likely to be required to support the renewable and more-distributed future grid.

With an increasingly complex task at hand, resource planners must rely on more advanced analytical tools and techniques. Modern planning tools leverage the advances in computing technology to drill down in finer and finer detail. Planners use "production cost models" or PCMs, which simulate power system operations and calculate the cost to serve load within the broader energy market and a utility's portfolio of generation and demand-side resources. These models are becoming increasingly sophisticated and require finer details, including using Monte Carlo simulation techniques and simulating dispatch down to 5-minute levels. We call these models "high-definition" or HD PCMs. Higher definition leads to deeper insights and more informed decisions. The regulatory standards of prudency state that planners must use all information known and knowable and achieve this standard by using the best HD PCMs available. Here are some key features of HD PCMs and why they should be used over traditional PCMs:

- **HD PCMs include weather as a fundamental driver of power system conditions**. Traditional PCMs operate under the foundational assumption that power price is approximated by fuel cost multiplied by the heat rate of the marginal unit to serve load. Much of the system energy in the future will be supplied by renewables with no fuel cost but seasonal and intermittent output. If weather is becoming the new fuel, planning models must include weather as a fundamental driver of power system conditions. Weather should be modeled as it actually behaves rather than simply using typical weather year or average shapes. Simulating weather conditions as it drives load and renewable output is the most robust approach.
- **HD PCMs capture risk and uncertainty.** Deterministic production cost modeling provides a single lens of the future by using hourly weather-normalized load, average wind and solar production, and market price fluctuations that have significantly less variability than actual observations. In the past, computing limitations made stochastic modeling impractical. Deterministic models were initially developed when computing power was significantly more costly and less available, but new systems have enabled more sophisticated modeling tools. Although the hourly deterministic production cost modeling adequately informed regulatory and merchant decisions over the last three decades, today, the limitations of this approach are increasingly exposed by high renewable penetration rates and the impact of weather (a fundamentally stochastic phenomena) becoming a major fuel source. HD PCMs use stochastic approaches to characterizing the uncertainty in weather, load, renewable production, power prices, gas prices, and forced outages. Capturing a properly correlated distribution of production cost outcomes helps drive planning towards a more robust risk-informed decision-making framework.
- **HD PCMs can simulate down to the 5-minute level -** When resource planning models moved from load duration curves to hourly chronological dispatch it represented a significant improvement. With the increase in renewable generation, models now need to step into the intra-hour or sub-hourly time dimension. Models that use hourly time steps gloss over the variable operations of flexible resources due to quick changes in renewable output in the intra-hour period. The value of a resource's ability to respond to real-time 15- and 5-minute prices (or perform sub-hourly renewable integration services) with quick start-up and ramping to full load with little to no start-up costs, is missed when only modeling at the hourly level.

3.2 REVIEW METHODOLOGY

The Ascend team reviewed the following key requirements for a modern IRP:

Stakeholder Process

The decisions utilities make have far reaching implications for stakeholders, including different classes of rate payers, power plant workers, environmental groups, shareholders, disadvantaged communities, and many others. Ascend reviewed each LSE's stakeholder process, including engagement with Tribal communities, to determine if stakeholder engagement was thorough, accessible, and meaningfully contributed to the final IRP.

Getting Inputs and Assumptions Right

The old saying, "garbage in = garbage out" is eternal. Getting the right results requires a thorough and thoughtful approach to investigating the state of the market and energy technologies that will be used as input assumptions. This is especially critical today when the costs of renewables and storage are declining so quickly.

- Does the long-term price forecast capture the changing dynamics of high-renewables systems? These include declining implied heat rates, changing power price shapes, and increasing price volatility. How were the price curves developed? What assumptions are behind those curves? Is it consistent with current and expected policy and economics?
- What are the cost curves associated with each power resource technology? Are they consistent with today's quoted prices and current cost curves from reputable sources such as NREL, Lazard, BNEF, etc.?
- What is assumed about the cost of carbon, either as a carbon tax, cap-and-trade, or social cost of carbon?
- How is load modeled? Are new types of loads such as electric vehicles included? How are load reducing technologies such as behind-the-meter solar and demand response captured? Are the distributed energy resource (DER) assumptions reasonable?

Avoiding Model Limited Choice

Model limited choice is when limitations in the modeling tools lead to poor decisions. For example, using weather normalized deterministic inputs rather than a simulation approach with weather as a fundamental driver, which results in undervaluation of flexible resources. Capturing volatility is critically important when renewables take up more share of the supply stack. Another example is failing to add the sub-hourly value of flexible resources. For example, today up to 70% of the value of storage is found in the intra-hour operation providing regulation and real-time market energy. An hourly only approach fundamentally undervalues storage relative to traditional resources. Additional things we look for include:

- How is reliability planning conducted? Is there loss of load probability analysis? What is the expected capacity contribution of renewables? Is there any planning for extreme events such as the summer 2020 western heat wave?
- How are ancillary services modeled? Do the IRPs take into account the increased need for A/S as a function of renewable energy penetration?
- How is integration with the Western EIM captured?
- How is cost calculated? How is NPV calculated? Is risk monetized and included in decision analysis?
- How is the model validated?

Developing a diverse set of Scenarios and Portfolios

A comprehensive approach to developing scenarios and portfolios is a best practice with respect to managing uncertainty about future conditions. Ascend leveraged its experience working across the country in resource planning to identify if there are any alternative scenarios and portfolios that would provide insight and benefit to the IRPs. In particular, the Ascend team reviewed:

- Are all potential policy pathways captured? This may include a national clean energy standard, carbon tax, state level renewable requirements, a Western RTO, etc.
- Are there scenarios around commodity prices (e.g. gas and power prices), and why?
- Does the LSE use a capacity expansion algorithm, or develop discrete portfolios? Are there sensitivity runs done and why? What was the process for developing discrete portfolios?

3.3 REVIEW OF APS IRP

3.3.1 IRP PROCESS

In developing the IRP, APS laid out several planning principles. First, APS notes that in January 2020 the company announced its goal to gradually transition to 100% clean energy by 2050. Interim goals along the path to 100% include achieving 65% clean energy by 2030 and eliminating coal by 2031. To achieve these goals, APS will rely on clean generation from Palo Verde nuclear power plant, increased energy efficiency savings, and significant deployment of renewable generation and battery storage.

APS started the IRP process in late 2018 with a group of stakeholders representing a wide range of utility industry experts from resource developers, environmental advocacy groups, and power companies. Some of the groups who submitted comments include the Sierra Club, Black Mesa Trust, Vote Solar, Southwest Energy Efficiency Project, Arizona State University, Calpine Energy Solutions, Western Resources Advocates, and Arizona Electric Power Cooperative. They conducted seven day-long meetings over a nine-month period. The meetings allowed the stakeholders to closely examine, question and provide feedback on the IRP assumptions and methods. Stakeholders proposed a wide range of portfolios to include in the IRP. The consulting firm Energy and Environmental Economics, Inc. (E3) conducted a high-level economic analysis with the stakeholder group. Ultimately, the efforts by the group led to the three portfolios included in the APS IRP analysis. Appendix F starting on page 540 of the IRP included a presentation from E3 regarding the stakeholder process.

E3 laid out three goals for the stakeholder process. First, they created a tool in Excel that allowed stakeholders to perform high level modeling on the proposed portfolios. The tool was meant to balance modeling complexities and time limitations while giving stakeholders results that are directionally consistent with industry standards. Stakeholders were able to test assumptions on technology cost, load growth, and other key variables. Second, E3 aimed to provide stakeholders with a more active means to participate in the portfolio planning process. Third, Stakeholders were able to put forth scenarios to study and inform APS's development of the IRP.

The main takeaways from the stakeholder process, as reported by E3, were

1. Continued population growth will drive significant investment in APS's system
2. Significant new clean resources will be needed to achieve carbon reduction goals

3. Broadly defined policies to encourage clean energy and carbon reductions provide more affordable and flexible options than prescriptive goals
4. Palo Verde is critical to meeting future clean energy goals at low cost
5. Early retirement of coal will have significant carbon benefits, but would require large replacement investments
6. Even with deep decarbonization, firm gas resources will be crucial for reliability while running infrequently

On page 26, APS dedicates several paragraphs to the collaborative stakeholder process in developing plans to transition to a clean energy future. The stakeholder process is key to charting a path to a carbon-free grid at a reasonable cost and meeting customers' changing energy needs.

APS did not include discussion in the IRP document regarding consultations with affected communities from coal retirements other than a small section on page 26 stating that APS is committed to working with its employees and stakeholders on the economic impact and other effects of retiring coal assets. In response to a data request, APS stated that they are planning to enhance energy efficiency offerings to the affected communities. Representatives from the Navajo and Hopi tribes submitted comments in the IRP docket arguing that APS has not made any indication of plans to work with tribal leaders in the development of renewable energy projects to replace the retiring coal. They feel strongly that APS has benefitted greatly from tribal coal while the tribal communities have endured negative environmental and health impacts from the coal power plants. To right the past wrongs, the tribal representatives argue that APS should commit to developing future renewable projects in collaboration with the tribal communities. They also argue that APS should retire all coal sooner than 2031.

The Sierra Club and Southwest Energy Efficiency Project provided comments that include independent analysis of the IRP portfolios. They claimed that the process of fulfilling data requests to build the independent analysis took a few weeks. The number of weeks and submitted requests were not specified.

3.3.2 INPUTS AND ASSUMPTIONS

Demand Side

For the IRP review, the inputs and assumptions to the forecast of annual energy and peak demand from 2020 to 2035 were disaggregated into five components. The first component is the "base" energy or peak demand, which represents the natural evolution of load driven by population and economic growth before accounting for the impacts of programs and new technologies. The remaining four components are:

- **Electrification:** The increase in energy and demand associated with electric vehicle adoption and the conversion of end uses to electricity.
- **Energy Efficiency**: The decrease in energy and demand associated with improvements in energy efficiency as a result of utility programs.
- **Distributed Generation**: The decrease in energy and demand associated with behind-the-meter generation, primarily photovoltaics.
- **Demand Response**: The decrease in demand associated with utility demand response programs.

The APS IRP data generally included the necessary data series for the 2020 – 2035 period of the IRP. APS's 2020 IRP provided a variety of data sources that were used to develop the forecast, including:

- APS 2020 DSM Opportunity Study
- APS Time Series Hourly Load Forecast
- Itron's review of APS's Load Forecast
- APS Coincident Peak Demand Disaggregated by DSM and by Month and Customer Class
- APS Energy Consumption by Month and Customer Class
- APS Forecast of EV Sales and Energy Consumption
- APS Forecast Documentation
- APS Staff Responses to Data Requests

The base energy forecast for APS increases from 28,905 GWh in 2020 to 47,448 GWh in 2035. The annual growth rate between 2020 and 2021 is approximately 4.1%, falling to 2.5% between 2034 and 2035. The annual growth rate in the APS baseload forecast is 2.5% between 2034 and 2035. The base forecast for peak demand shows growth from 7,470 MW in 2020 to 11,271 MW in 2035. The annual peak demand growth rate in 2020 is 2.41% substantially lower than the energy forecast. The annual peak demand growth rate between 2034 and 2035 is 2.37%, very similar to the 2020 peak demand growth rate and the energy growth rate during this period. Given assumed growth in customers, we feel these are reasonable growth rates for energy. We also find that lower relative demand growth is a reasonable expectation as peak demand becomes muted by adoption of load modifying technologies like behind-the-meter solar and storage, controllable loads, and smart EV charging.

The electrification data provided by APS included base, transformative, and blended EV adoption scenarios. The APS EV forecast for 2019 estimated annual usage at 40 GWh growing to 56 GWh in 2020. The APS EV usage is forecasted through 2038, where annual usage is expected to be 1,714 GWh, roughly 300,000 EVs. The growth rate in electrification energy use exceeded 100% during the early 2020s, declining to under 20% by 2035.

In addition to the IRP, Verdant reviewed the APS 2021 DSM plan, which has a target of approximately 335,000 MWh of annual energy savings from efficiency measures while the APS Energy Consumption by Month and Customer Class listed an incremental 2021 energy efficiency program saving of approximately 175,000 MWh. The targeted energy savings in the 2021 DSM plan, closely approximate the energy efficiency savings necessary to meet the proposed Energy Rules targets.

Supply Side

Existing Resources

APS provided a review of the existing supply side resources along with potential candidate resources. The existing resources include:

- Palo Verde, a large nuclear power plant near Phoenix, of which APS is the majority owner with 1,146 MW. APS assumed that Palo Verde will be part of the portfolio through 2035.
- The Four Corners and Cholla coal-fired power plants, with 1,357 MW of combined capacity. Given APS's stated plans to transition to a clean energy system, they will retire all coal power by 2031 with Cholla going offline in 2025 and Four Corners in 2031. No early retirement scenarios for coal were considered in the IRP.
- Natural gas generation comprises the largest share of existing resources in the APS portfolio. There are eight natural gas generation stations owned by APS for a total nameplate capacity of 3,573 MW plus an additional 1,660 MW of purchased power from natural gas resources. Five of the plants have units that are over fifty years old, meaning that a portion of the existing natural gas capacity is likely

to retire over the next 15 years. APS views natural gas as a resource that allows greater integration of renewables due to the flexibility of gas-powered assets. The lower carbon emissions, compared to coal, also make natural gas a bridge resource enabling the transition to a carbon-free future. Over time, APS acknowledged that natural gas plants must also transition to a low/no-carbon resource, potentially by converting to hydrogen/renewable fuel or employing carbon capture technology.

- Renewables make up 883 MW of APS resources with solar providing 567 MW. This does not include customer-owned solar, which is currently at 1,044 MW. Wind comprises 289 MW from three locations with two of the locations in neighboring New Mexico.

APS also controls two microgrids totaling 32 MW in capacity. One of the microgrids serves a Marine base in Yuma and the other serves the Aligned Data Center near Phoenix. Both grids act as redundant sources of power for the customers in the event of an outage.

Future Resources

APS considered a wide variety of new resources for use in the portfolios. In the report they list thermal (natural gas turbines and combined cycle plans), nuclear (advanced reactor technology and small modular reactors), renewable (wind, solar, geothermal and biomass), and storage options that were considered. The storage options covered Li-Ion batteries, flow batteries, compressed air energy storage, and pumped hydro storage. A footnote states that all storage technology options assumed four hours of duration, which is inconsistent with industry standards for compressed air energy storage (CAES) or pumped hydro storage. Generally, resource planning assumes CAES and pumped hydro will provide long-duration storage of at least 8 hours, usually up to 12 hours.

Technology Costs

Table 2-3 in the IRP document lists assumed costs for potential future resources in dollars per installed kilowatt for the year 2022. APS provided future cost curves for all potential resources as part of a data request. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. The exceptions are for solar PV, batteries (lithium-ion and flow), and wind. Solar PV and batteries are assumed to get cheaper over the time horizon of the IRP, while wind costs are expected to increase, although at a slower rate than thermal assets.

Technology cost assumptions for renewables and batteries used in this IRP are in line with other reputable resources. Projections used in the APS IRP are shown in the following graphs with comparable cost curves from Ascend for storage and the National Renewable Energy Laboratory (NREL) for solar and wind. The cost projection used by APS for energy storage, utility scale solar, and wind are lower in all graphs.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 1: Capital cost comparison (li-ion 4-hour battery)

[Redacted due to confidentiality]

Figure 2: Capital cost comparison (utility scale solar PV)

[Redacted due to confidentiality]

Figure 3: Capital cost comparison (onshore wind)

(End confidential information)

Market Assumptions

APS engaged E3 to develop power price forecasts at the Palo Verde trading hub. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information).*** By 2035, excess solar during on-peak hours is expected to drive prices down well below the off-peak hours. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. The APS price forecast created by E3 closely matches Ascends price forecast on an annual basis by the year 2030. In the early years, Ascend's price forecast is much higher because it is anchored to power prices in the futures' market for power traded at Palo Verde. While the two forecasts converge on an annual level, the Ascend forecast keeps on-peak prices higher than off-peak prices during the middle of summer, shoulder months have higher off-peak prices than on-peak prices.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 4: Palo Verde annual power price comparison

[Redacted due to confidentiality]

Figure 5: Palo Verde monthly power price comparison

(End confidential information)

Natural gas prices are shown in the model as rising very slightly over the study period. From 2021 to 2035, APS estimates natural gas to rise from $2.25 per MMBTU to about $2.80 per MMBTU. APS derived the forward curve for natural gas prices from an analysis of market forward prices. Ascend used a similar method to derive natural gas prices and produced a forecast that is slightly lower than the APS forecast.

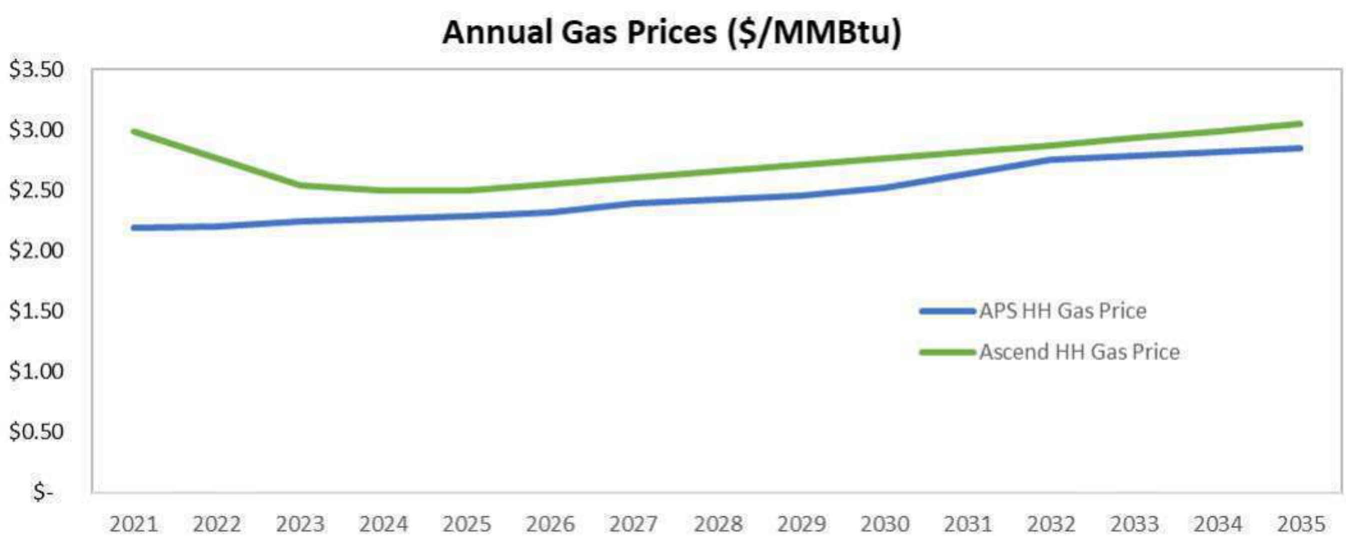


Figure 6: Henry Hub annual gas price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 7: Henry Hub monthly gas price comparison

(End confidential information). Implied heat rates function like a normalized power price that accounts for the impact of gas prices and are an indicator of whether gas generation resources can operate profitably in the market. On average, Ascend and APS's implied heat rates are fairly aligned. The difference in the first years is a result of having higher gas prices in the Ascend assumption due to alignment to market forwards. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. APS spring and summer heat rates are relatively low leading to depressed valuation for gas resources.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 8: Annual implied heat rates, calculated as power price in Palo Verde divided by gas price in Henry Hub

[Redacted due to confidentiality]

Figure 9: Monthly implied heat rates, calculated as power price in Palo Verde divided by gas price in Henry Hub

[Redacted due to confidentiality] ***(End confidential information)***. APS used the currently traded prices as the baseline for carbon price modeling. Overall, APS' forecast is fairly aligned with Ascend's but is however likely to underestimate the cost of market purchases and the value of market sales, which could lead to an undervaluation of portfolio resources.

Modeling Approach

Demand Side

In Verdant's opinion, APS's IRP demand forecast was developed using industry best practices. They hired third-party consultants to assist in the development of forecasts of DSM opportunities or DSM potential and EV Sales and Energy Consumption. They hired Itron, a leading load forecasting firm, to review the APS load forecast, and APS responded to this review by adopting one of Itron's suggested methods to improve the residential load forecast. APS's growth in their load forecast is largely due to forecasts of growth in Arizona's population, business growth and growth in data centers. Given previous growth in Arizona's population, the forecasts of these underlying input to energy consumption appear within the likely bounds.

APS's DSM potential forecast appears thorough. The DSM forecast provided by APS is slightly higher than the DSM forecast in the IRP. Forecasting EV purchases and energy usage is a highly uncertain activity given the nascent nature of this market, but APS's use of a forecast developed by Guidehouse, a well-respected market research firm, highlights APS's effort to develop tools and establish an initial forecast of energy usage for this technology.

Supply Side

In previous IRPs, APS used capacity expansion modeling to determine a least-cost portfolio that meets future load growth. But for this plan, APS wanted to develop a range of portfolios representing a measured pace of renewable and storage implementation on one end (Bridge Portfolio) to meet their Clean Energy Commitment, a very aggressive pace of renewable and storage implementation (Accelerate Portfolio) on the other end, and one in between (Shift Portfolio). In previous IRP's, APS used capacity expansion models to create portfolios, which is standard in resource planning. In the 2020 IRP, APS stated that they "wanted to develop a range of portfolios representing a measured pace of renewable and storage implementation on one end (Bridge Portfolio) to meet our Clean Energy Commitment, a very aggressive pace of renewable and storage implementation (Accelerate Portfolio) on the other end, and one in between (Shift Portfolio)." For the 2020 approach, APS stated "the capacity expansion model would not correctly model the more diverse resources." This is a critical flaw in the APS modeling software. High levels of renewable resources in a model add complexity but should not be a barrier to implementing a capacity expansion model. APS would have been better off running capacity expansion models with varying limits set for carbon emissions. APS ended up using a capacity expansion model to construct a least-cost "technology agnostic" portfolio to be used as a benchmark for the analysis of the other portfolios.

The **Bridge portfolio** added solar, wind, lithium-ion batteries (four-hour duration), and natural gas combustion turbines to meet future capacity and energy needs. These resources were selected to achieve stringent carbon targets at the lowest cost. The natural gas combustion turbines were assumed to be "hydrogen ready" in that they could burn up to 30% green hydrogen at any point and ultimately be converted to burn 100% green hydrogen in the future. The **Shift portfolio** increased the renewables and battery builds to replace APS owned natural gas generation in the Bridge portfolio; natural gas tolling agreements were allowed to grow in the Shift portfolio. The **Accelerate portfolio** eliminated all future natural gas additions and increased the renewables and batteries significantly to meet future needs. No existing natural gas was assumed to retire by 2035 in the models.

In addition to the clean energy goal, all portfolios included APS's commitment to installing 850 MW of battery storage by 2025 with more storage added later. All portfolios also included the commitment to retiring Four Corners and Cholla coal plants in 2031 and 2025, respectively. APS did not consider earlier retirement dates in the models for either of the coal plants.

Table 7-6 on page 137 of the IRP provides a high-level comparison of the portfolio additions showing capacity by resource type. These are replicated below and are shown in MW.

Table 2: Capacities by resource type for APS portfolios

	Bridge	Shift	Accelerate	Tech Agnostic
Demand Side Management	1,602	1,602	1,602	1,602
Demand Response	693	743	793	693
Distributed Energy	1,585	1,585	1,585	1,585
Renewable Energy	6,450	7,950	10,375	750
Energy Storage	4,850	6,500	10,550	850
Merchant PPA/Hydrogen-ready CTs	1,859	1,135	0	5,115
Microgrid	131	131	6	281
TOTAL	17,170	19,646	24,911	10,876

APS included a 15% reserve margin in all portfolios. It tested this reserve margin with a resource adequacy model for the years 2020 to 2024 which is the window covering its action plan. Beyond 2024, when the portfolios become more dependent on renewables and batteries, it is not clear if the portfolios meet the industry standard "one day in ten years" loss of load event.

A summary of the portfolio results is shown in Table 7-8 on page 140 of the IRP. As expected, the Accelerate portfolio provides substantial gains in clean energy generation, carbon reductions, water use reduction and natural gas consumption. However, it is also significantly more expensive than the Bridge and Shift portfolios.

Table 3: Summary results of the APS portfolios

	Bridge	Shift	Accelerate	Tech Agnostic
Clean Energy	79%	84%	91%	52%
Renewable Energy	58%	66%	77%	21%
Revenue Requirement NPV 2020-2035 ($Billions)	26.6	26.9	28.4	24.9
System Cost Avg Annual Increase 2020-2035 (% per year)	1.3%	1.7%	2.8%	0.2%
Cumulative Capital Expense 2020-2035 ($Billions)	17.9	20.8	28.1	8.9
CO2 Emissions Reduction 2035 to 2005	69%	77%	86%	33%
Renewable Curtailment in 2035	17%	20%	23%	0%
Water Use in 2035 (1000 acre-ft)	36.0	33.6	30.2	42.5
Natural Gas Usage in 2035 (BCF)	74.0	53.9	27.3	176.7

APS performed sensitivity analyses on the portfolios by adjusting the natural gas price curve, carbon price curve and load growth forecast. The natural gas price sensitivity range went from a low case that is 23% below the base case to a high case that is 83% above the base case. Carbon prices ranged from zero to a curve that started at $19 per ton in 2025 and escalated at 7.5%. For the load forecast, APS ran the sensitivities required by the ACC: a zero-load growth and a load growth less than 1% (APS chose 0.9%).

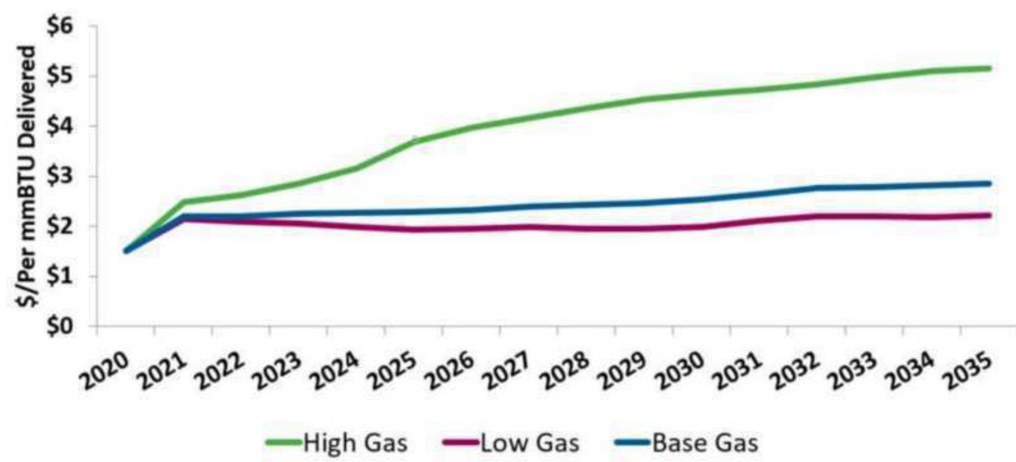


Figure 10: Natural gas price sensitivities

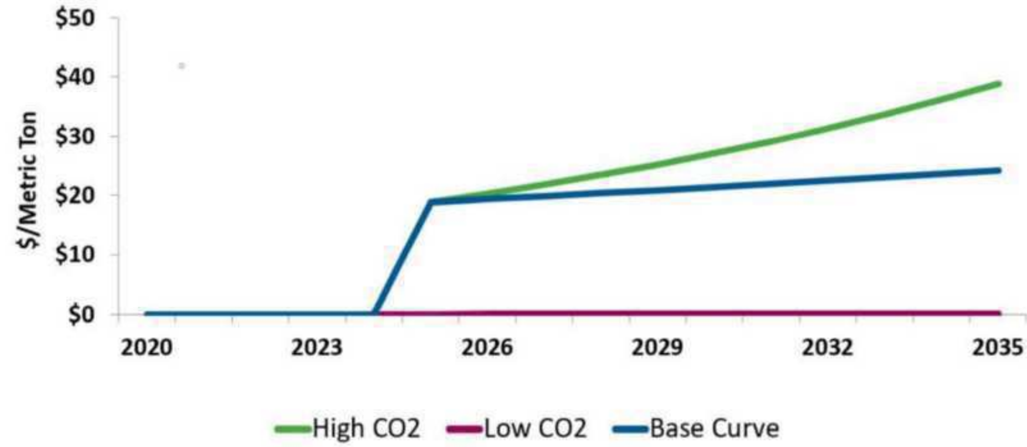


Figure 11: Carbon price sensitivities

This analysis showed that revenue requirements are sensitive to the three variables. The range of natural gas prices modeled caused revenue requirements to move up as much as 4% and down as much as 1%, for a potential swing of 5% depending on the future path. For context, the difference in revenue requirement between the Bridge portfolio and the Accelerate portfolio is 6.8% so an increase in 4% due to higher natural gas prices is significant. However, it is unlikely that natural gas prices will turn out to be 83% higher than APS expects.

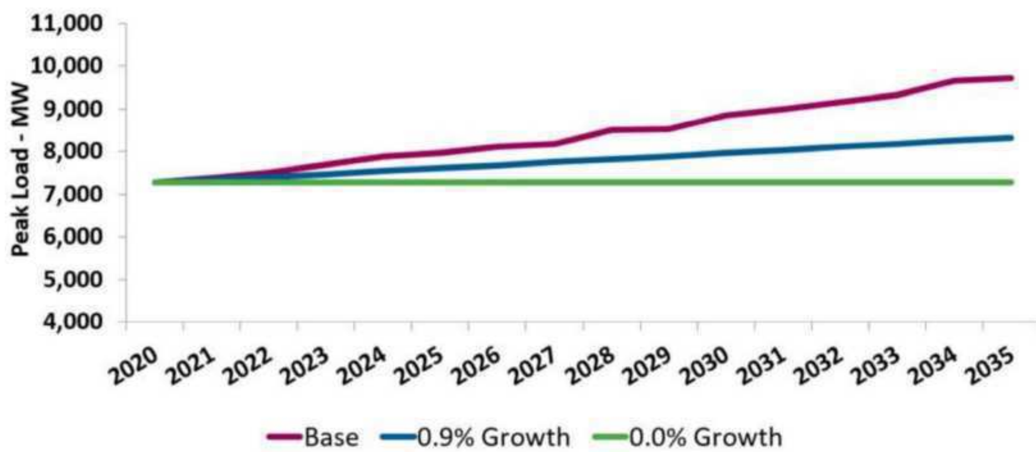


Figure 12: Load forecast sensitivities

Carbon prices were found to have less impact on revenue requirements. The range of carbon prices investigated resulted in the revenue requirement swinging from 3% below the base case to 0.4% above the base case. The large share of clean energy means that carbon price fluctuations will not affect operating costs significantly.

The load forecast sensitivity seems to be unrealistic given that APS believes load will grow at 2.5% annually. Model results based on zero load growth have no practical value because zero load growth is not a realistic projection at this time. The 0.9% projection, however, could be a realistic low growth case (assuming population declines) and shows that revenue requirements would be 5.3% lower if load grows at 0.9%.

APS feels that all three of the paths analyzed are viable options to move forward. Depending on the policy goals, APS could take an extremely aggressive path towards decarbonization or a more modest path. Either way, APS believes that it can meet stringent carbon reduction goals at a reasonable cost with any of the paths presented.

3.3.3 REVIEW OF MUST RUN ASSUMPTIONS FOR FOUR CORNERS POWER PLANT AND SOLANA PPA

On July 21, 2021, ACC Chairwoman Lea Marquez Peterson requested a review of the "must-run" assumptions on the Four Corners coal-fired power plant, which APS expects to retire after the expiration of the coal contract in 2031 as well as a review of the "must-run" assumption of the Solana concentrating solar power purchase agreement.

Regarding Four Corners she states:

> *As I understand from the stakeholders' filings, the primary concern is that failing to consider earlier decommissioning dates for the Four Corners Power Plant (inclusive of all costs associated with exercising early termination clauses and creating ratepayer-funded stranded assets) and replacing the plant's capacity with an equally reliable but significantly lower-cost resource (such as solar paired with battery storage) results in resource scenarios and portfolios that are not adequately represented or considered in APS's 2020 IRP. In particular, the stakeholders are concerned that failing to run a model representing such considerations would not allow the Commission to conclusively know which prospective resource mix could result in APS's "least cost" portfolio.*

Regarding the Solana PPA she states:

> *In filings made by one of the above-mentioned stakeholders on July 12 and 21 2021, it was revealed or otherwise alleged that APS knowingly entered into a 30-year PPA with a third-party power producer, Solar One, LLC, to procure above-market priced thermal solar power from Solana Generating Station at a rate of over four-times the levelized cost of energy in 2020 (the PPA, the "Solana PPA"). According to the stakeholder's filing, the Solana PPA is an issue because, according to the stakeholder, APS knew at the time of investment that the cost associated with the Solana PPA would be significantly higher than other sources of renewable energy and that ratepayers would be locked into this high price (even as the market cost of solar decreases) for at least a decade.*
>
> *Because the company was able to pass through the above-market costs of this PPA (about 14 cents per kWh) the stakeholder has alleged that ratepayers may have been paying an outrageous price for solar since the time of entering into the PPA, despite the fact that it was not the most prudent or cost-effective source. To substantiate the stakeholder's claims, the stakeholder has requested the Commission conduct an "external audit" of the pendency of the Solana PPA.9 Based on my understanding of utility PPAs, APS would plan to fulfill its contractual obligations with third parties and, thus, would be likely to apply a "must-run" assumption to its Solana PPA, as well...*
>
> *...In particular, it may prevent the Commission from knowing which prospective resource mix could truly represent APS's "least cost" portfolio, and it may result in ratepayers paying more than is reasonable and prudent, for longer than is reasonable and prudent, for equally reliable solar renewable energy that could be procured at a lower cost, all else being considered.*

The Chairwoman's Perspective then states:

> *Applying "must run" assumptions to the Four Corners and Solana resources may represent an approach that does not take into account all sources that can cost-effectively meet a utility's load forecast, and therefore could result in scenarios that do not truly represent the utility's "least cost" portfolio. Lacking this analysis would prevent the Commission from truly knowing which resource portfolios may balance the interests of reliability, affordability, and sustainability most effectively*
>
> *Accordingly, I would like Ascend Analytics to address in its report or a supplemental report the issue of APS's "must-run" assumptions on Four Corners and Solana by providing a brief narrative describing whether, in Ascend Analytics' sole discretion, APS's "must-run" assumptions result in portfolios or scenarios that, again in Ascend Analytics' sole discretion, are not adequately represented or considered in APS's RP. To be specific, this request is not a request for Ascend Analytics to run additional models. Rather, it is a request for Ascend Analytics to provide a brief narrative of the third-party consultant's independent opinion. In the interest of time, this opinion could be stated as simply as whether the third party-consultant believes the assumptions do or do not result in portfolios or scenarios that are or are not adequately reflected.*

Ascend Analysis of the Four Corners Must-Run Assumption

Ascend finds that the designation of "must run" for Four Corners is reasonable in the context of the planning principles outlined in Section 3.1, in which all decisions are not simply an optimization of any one factor but a balancing of the tradeoffs between multiple planning principles. In our opinion, it is likely true that the must-run constraint on Four Corners does not result in the least-cost portfolio. We also believe that APS should have shown a scenario in which Four Corners is retired prior to 2031 as a comparison point with the three proposed portfolio pathways. However, even if retiring the plant earlier could result in a lower cost portfolio, there are other valid reasons stemming system reliability as well as difficult contractual issues with co-owners of the plant.

APS is a co-owner of Four Corners with TEP, SRP, PNM, and NTEC (a Navajo Tribal Corporation). The co-owners have a contract with NTEC for a minimum coal delivery per year. The minimum uptake per year roughly translates to a 60 – 65% capacity factor of the power plant. Theoretically, APS could buy its way out of the contract before its expiration in 2031, but this would have to be a negotiated settlement between all the co-owners.

Setting aside the challenges of finding agreement between the ownership parties, issues around system reliability remain paramount. In the Rebuttal Testimony of Brad J. Albert on Behalf of Arizona Public Service Company[2], Mr. Albert expresses concern that the Western region is becoming too short on capacity to rely on generic market purchases.

> *I have little confidence that APS would be able to contract for reliable generating assets in the future. Over the past decade, thousands of MW of generation have been removed from the western market, either through retirement or utility purchase of the once large supply of merchant generation. Generation retirements for example include Four Corners Units 1-3, Cholla 2, Navajo Plant, and San Juan Units 2 and 3. California has retired San Onofre Nuclear Generating Station (SONGS) and many natural gas once*

[2] Staff Informal 3.1_APS16462_Brad Albert Testimony (Alll)_19-0235 Rate Case. REBUTTAL TESTIMONY OF BRAD J. ALBERT On Behalf of Arizona Public Service Company Docket No. E-01345A-19-0236

through cooling units. More retirements are anticipated in the next few years including Cholla 4 by the end of this year, followed by San Juan 1 and 4 in 2022, and Cholla 1 and 3 in 2025. The market is too tight to assume that it can provide for the reliable replacement of Four Corners 4 and 5 if they were to retire early.

He also states that solar and four-hour storage is not a one for one replacement for a base load coal plant.

If Four Corners were to retire before 2031, APS's share of Four Corners would likely need to be replaced by more than 1,000 MW of additional renewable generation plus 1,400 MW of battery energy storage on top of what is reflected in the IRP.

Ascend is not specifically commenting on Mr. Albert's assertions, although we find his concerns to be valid. Solar and four-hour duration storage does not provide the same services as a baseload coal plant. Coal plants provide energy around the clock and have a stable and reliable fuel supply, albeit coal plants generally have higher forced outage rates than solar and storage plants. A suitable clean energy replacement for Four Corners might also include wind, geothermal, and possible longer (8+ hours) duration storage. We agree that APS should not rely on generic market purchases given the situation Mr. Albert describes in the West in which legacy generation is rapidly closing and being replaced with weather driven renewable generation and energy duration limited storage resources. California is experiencing extremely tight capacity situation and generally relies on neighboring states to fill in the breach when load peaks during ever more frequent heat waves. Until such time as APS joins a future western wide balancing authority (otherwise known as a Western RTO), it is responsible for maintaining resource adequacy within its own service territory without relying on outside market purchases. It is not prima facie obvious that simply shutting down the plant by 2023 or as soon as practicable and replacing it with solar and storage is reliable or economic.

In the final analysis, we agree that this "scenario," an early retirement of Four Corners, should have been explicitly modeled. This scenario may even have been "least-cost". At the same time, APS could have also demonstrated that even if least-cost, that it would not be an acceptable portfolio if it failed to provide the necessary reliability performance. The best way to demonstrate this is using loss of load expectation analysis within the resource selection process to make sure all portfolios are comparable and meet the minimum criteria for reliability.

For the next IRP, we recommend APS explicitly models an earlier retirement date for four corners to demonstrate all aspects and implications of such a decision and more information will be available as to the performance of batteries to maintain system reliability from California.

Ascend Analysis of the Solana PPA

The Solana Generating Station is a 280 MW concentrating solar power plant developed by Arizona Solar One LLC (a subsidiary of Abengoa S.A). The PPA for Solana's generation was executed in 2008 with the goal of meeting Arizona's renewable energy standard (RES) of five percent of retail sales from renewable energy resources by 2012. In 2008, solar energy technology was in its infancy commercially speaking, so it was many times more expensive than it is today. At the time of the PPA execution, APS noted that the energy cost 19% above market[3]. According to the ACC Decision 70531, the PPA was selected through a competitive process and was deemed an

[3] Staff Informal 3.1_APS16453_Application for Approval of CSP

"appropriate component of APS' renewable energy portfolio and is compatible with APS' implementation plan as approved in Commission Decision No. 70313 [4]".

One can only evaluate a decision in the past using the information that was known at the time. In 2008, concentrating solar plants with molten salt storage were considered more cost-effective than solar photovoltaic technology. From today's perspective, the PPA contract is certainly badly "out-of-the-money" for renewable energy, however it is not reasonable to expect that APS should have known that at the time. A thirty-year term does mean taking on substantial risk that the asset would someday be highly uneconomic, however in 2008 renewable development was considered so risky by the finance community that these tenor lengths for off-take were required for the project to receive funding.

Directly addressing the Chairwoman's letter, the term, "must-take" is not applicable in this case in the same way it is for Four Corners. Solana has limited dispatchability and it does not have fuel cost. APS also does not own Solana; the contract is a power purchase agreement, whereby APS only pays the project owner for what energy gets delivered. Unfortunately, in hindsight this appears to be a bad contract for ratepayers, and perhaps more due diligence or more effort to negotiate a shorter-term length could make ratepayers better off. Nonetheless, APS is contractually obligated to take the energy under the terms of the agreement. Therefore, it is appropriate to model the resource in the portfolio as such.

3.3.4 REVIEW OF PREFERRED PORTFOLIO

APS did not specify a preferred portfolio. Instead, they developed an action plan based on the three portfolios they analyzed. The action plan covers the period from 2020 to 2024. The three portfolio models were nearly identical during the years 2020 to 2024 so APS can move along this path now while monitoring technology improvements to determine the optimal path in a future plan. Chapter 7 of the IRP, starting on page 157, covers the Action Plan for APS.

Demand Side

On the demand side, the action plan is built on continuing a high level of investment in demand side management, the energy efficiency plan focuses on measures contributing to peak reduction and the program dramatically increases programs designed to shift load through demand response and load management. The IRP states that demand response will contribute 193 MW of demand reduction from 2020 to 2024. This reflects a growing emphasis on demand response and load shifting programs. The distributed generation programs show slower growth during this period, potentially due to some programs being closed to additional enrollment (see page 161 of the IRP).

Supply Side

On the supply side, the Action Plan specifically covers expansion of renewable resources, increased energy storage, APS solar communities and growth in demand side resources. To meet the interim goal of 45% renewables by 2030, APS needs to add 300 – 400 MW of renewables annually through 2024. APS listed four outstanding requests for proposals (RFPs) covering 150 MW of solar plus storage, 150 MW of solar PV, 250 MW of wind, and 75 MW of demand response. APS will need to ramp up this effort to maintain the 300 – 400 MW of added capacity per year. To make the best use of renewables, APS has committed to procuring 850 MW of battery

[4] Staff Informal 3.1_APS16458_DECISION No 70531

storage by 2025. During the writing of the IRP, APS had paused the effort to expand energy storage due to the McMicken energy storage facility fire investigation. The pause forces APS to revise its battery project timelines which means APS will rely on short-term market purchases to meet summer peaking needs until battery capacity is ramped up.

Part of the action plan involves continued operation of certain existing resources. APS leases 42% of its share of Palo Verde nuclear facility through three separate agreements with the first agreement expiring in 2023 while the two remaining agreements expire in 2033. APS is committed to extending the Palo Verde leases. APS also plans to maintain its gas fleet during the transition to renewables. Natural gas generation provides firm capacity and reliability to APS, and natural gas prices are expected to remain low for the foreseeable future. APS did not specify details to transition away from natural gas over time.

Transmission improvements are a key part of enhancing reliability while growing renewables in APS. The 2020 – 2029 Transmission System Plan includes 26 miles of 230 kV lines, 3 miles of 115 kV lines and 38 new transformers. In total, APS plans to spend $590 million on transmission investments.

3.3.5 RECOMMENDATIONS TO IMPROVE IRP

Demand Side

Overall, there are not significant shortcomings with the load modeling and energy efficiency savings modeling in APS's IRP. APS maintains a substantial amount of detail and documentation to support their IRP. The energy efficiency forecast provided in the IRP and the supporting documents was inconsistent with the requirements of the energy rules. The energy rules, however, were finalized after the finalization of the IRP, so this inconsistency is not surprising.

Supporting information on the cost of the energy efficiency, distributed generation, and demand response programs would have been helpful to better understand how the increased demand response saving will be achieved. The details supplied on the most recent DSM potential study appear to indicate that maintaining energy efficiency savings consistent with the energy rules for an extended number of years may be difficult. Potential studies often show that energy efficiency savings can be shifted to occur into earlier time periods with aggressive programs (much like the energy rules), but without advancements in technologies (new technologies added to the study and to APS's DSM programs), it may be difficult to maintain an aggressive level of savings as opportunities become saturated.

Finally, more comprehensive and clear documentation would be helpful. It was difficult to connect the extensive data that was provided with the description of the plan in the IRP.

Supply Side

APS analyzed three portfolios to investigate three potential future paths with differing levels of renewables and energy storage. The portfolios were manually assembled with specific objectives in mind. The first recommendation to improve the IRP process is to use a capacity expansion model to determine the least cost combination of resources that would meet APS's future goals regarding clean energy generation and carbon emissions. The capacity expansion model approach also allows APS to run scenario analysis to show how the optimal resource selection changes with adjustments in on technology cost assumptions, load growth and carbon prices.

The production cost model input files indicate that APS included spinning and non-spinning reserves but did not include regulation up and down. The portfolios considered in this IRP contains vastly different amounts of renewables which drives the need to different levels of regulation to maintain operational reliability. Realistically, the amount of battery storage in the model is high enough to easily provide the necessary levels of regulation reserve to cover the variability from the high level of renewables. In a future IRP, APS should provide some context around the amount of regulation they currently use and the amount they expect to need to balance the high amount of renewables expected in the future. They should also include regulation in the production cost models to include the cost of serving regulation and energy from the dispatchable resources.

APS is a participant in the CAISO Energy Imbalance Market (EIM). The EIM provides APS with real-time access to wholesale energy trading at a five-minute time step. APS should include this in the IRP modeling instead of relying on hourly production cost models. When five-minute prices and dispatch are used in a production cost model, the value of flexible resources is revealed. The results would have shown significantly improved economics of energy storage relative to other resources. Batteries provide flexible capacity which can capture additional revenue in the EIM by ramping up and down in response to five-minute EIM prices. Real-time prices at the five-minute time step tend to be much more volatile than hourly prices, meaning that EIM prices will have large price spikes lasting a short period along with more frequent negative prices. Additionally, EIM access provides the ability to sell excess solar generation in the middle of the day which makes it an important aspect to APS operations that is neglected in hourly models.

The resource adequacy model shown in the IRP covered the years 2021 to 2024 and shows the APS portfolio to be reliable in the near term. APS used this model to determine whether a 15% reserve margin provided adequate capacity to meet future load. However, it appears that APS did not run a resource adequacy model for future years when it expects to have a much higher mix of variable energy from wind and solar. This does not mean the modeled portfolios are not adequate in the future years, but APS should confirm the reliability of the modeled portfolios going to 2035. This exercise would allow them to determine the proper amount of storage needed to maintain reliability with high levels of wind and solar expected. Additionally, APS should include the possibility of extreme weather affecting the resource adequacy as it did in the 2020 heat wave. Resource planning can no longer sample weather from the past and expect the future to be similar.

Power system operations are heavily dependent on weather which drives the load, renewable generation, and market prices. APS should consider using a model that uses weather to simulate load, renewable generation, and market prices. APS is on a path to a high level of renewable energy; they should consider modeling tools that can realistically replicate the dynamics of a high renewables system.

APS ran scenarios for the price of natural gas, price of carbon and the load growth in the sensitivity analyses. A key analysis that was missing is the sensitivity of market prices. High and low market prices will lead to vastly different outcomes that should be considered when making long-term resource plans. Including the market price sensitivity as part of capacity expansion models would add a lot of value to the analysis.

APS should consider alternative retirement scenarios for the coal resources. Keeping coal until 2031 without considering the possibility of an earlier retirement appears to be shortsighted given the frequency of coal closures in the WECC, mostly driven by economics. APS would serve ratepayers well by considering multiple options for transitioning out of coal.

Finally, the Technology Agnostic plan that APS showed as a benchmark provided no real value since it was not a realistic option for APS to build. Future IRPs should use a benchmark that meets minimum policy goals for clean energy or carbon emissions and show the least cost solution to meet the planning requirements.

3.4 REVIEW OF TEP AND UNSE IRPS

Tucson Electric Power and UNS Electric are owned by the same holding company and share the same resource planning staff. For the most part, the IRPs are highly similar, including using the same tools, inputs, and assumptions. For simplicity and to reduce unnecessary repetition, the following review includes both TEP and UNSE's IRPs. Differences between the two IRPs are specifically identified and discussed.

3.4.1 IRP PROCESS

TEP created an advisory council, consisting of customers, local government, and advocacy groups to guide the IRP process. The advisory council met once in 2019 and once in 2020. TEP discussed a range of topics in the Advisory Council meeting from load forecasting to resource costs and coal plant economics. While engaging with stakeholders is important in the IRP process there are key affected communities that were not part of the process, including any mention of working with Tribal Nations.

UNSE mentions stakeholder workshops in December 2019 in Lake Havasu City and Kingman but does not provide additional detail in its IRP. However, UNSE identified several governing themes from these workshops for their IRP process: recognizing declining costs of renewables and storage; avoiding large bets on long-term assets with uncertain futures; and maintaining affordability as UNSE transitions from reliance on the market to reliance on self-owned assets.

The IRP would have benefitted from a request for information to provide more detailed information on resource costs and availability. However, this concern is mitigated by UNSE's plan to procure future resources through all-source RFPs, which will ensure that resources will be procured with the best available current cost information at the time of procurement, rather than being locked-in to procurement decisions based on assumed costs that can quickly become outdated or inaccurate.

3.4.2 INPUTS AND ASSUMPTIONS

Demand Side

The consideration of supply side resources inherently requires an understanding of the projected energy and peak demand requirements. In the context of an IRP, this should extend to the various factors that affect both the amount and timing of consumption, which for this review the key resources were energy efficiency, demand response, distributed generation, and electrification.

For gross energy and peak demand, the IRPs provided forecasts by sector to 2035. The energy forecast for TEP increases from 8,970 GWh in 2020 to 11,721 GWh in 2035, with an average annual growth rate of 1.8%. The base forecast for peak demand shows growth from 2,589 MW in 2020 to 2,931 MW in 2035. The average annual growth rate of 0.8% is substantially lower than the energy forecast.

The electrification data for TEP consisted of a forecast of the annual energy associated with EVs, beginning with a total of 7 GWh and increasing to 786 GWh in 2035. Given the low starting point and anticipated adoption, the annual rate of this growth in these data varied greatly, starting at more than 200% per year and declining annually. The data provided by TEP show that by 2035, around 45% of TEPs residential customers will have an electric vehicle (assuming an annual consumption of 4,000 kWh). The peak demand for EVs assumed that most charging will occur off peak.

Both historically and in its forecast, TEP has only a small presence of peak demand savings from demand response. The 2020 DSM plan shows 41 MW of savings, representing about 1.6% of the system peak – increasing to 57 MW in 2050. Distributed generation from 2020 to 2035 shows incremental peak demand savings of 3 MW in 2020 increasing to 57 MW in 2050. Using the assumption that most of these savings are due to solar, they translate into 5.3 GWh of energy savings in 2020 increasing to 123 GWh in 2050. This represents a tiny amount of the potential for demand savings from technologies such as smart thermostats and behind-the-meter solar and storage. We believe demand response and DER adoption should be given more consideration in future IRPs.

The forecasts suggest reasonable rates of growth, but there are some shortcomings to the data. For one, while these forecasts account for the effects of the energy efficiency and distributed generation, though the amounts associated with these resources are not broken out. Additionally, the rate of growth for energy is markedly higher than peak demand, which is a discrepancy that merits more explanation. The inputs to these forecasts come from the various data sources used to develop the forecasts, which are laid out later in the discussion of modeling.

Energy efficiency is discussed sparingly in the IRP and concrete data are limited to tabular summaries of aggregate peak demand savings and a few graphical representations in the context of all sources of load. The bulk of the information on energy efficiency came in the data requests, but these have little information on the underlying assumptions. For example, one of the responses to the data request included a series of the combined energy efficiency and distributed generation that were incorporated into the energy forecast, making it difficult to assess them separately. It would have been better to review the utilities' energy efficiency potential studies, which would have provided an understanding of the technological, economic, and market factors underlying the projected energy efficiency resources, but these were not available for review.

Both IRPs also provided limited information on electrification. Electric vehicles are discussed generally in the IRPs, mostly in terms of global or national trends for adoption. The details on electric vehicles came in the responses to the data requests, where both utilities provided an annual series of the total energy. While the overall energy values are reasonable, the band is wide given the high uncertainty over adoption. Nevertheless, the series were provided with no underlying assumptions (type of fleet, numbers of cars, average annual consumption per car, etc.), which would have made it easier to determine the defensibility of the projections.

Demand response is similarly discussed in generalities as a resource for both TEP and UNSE and the IRP only presents its limited role in a few graphical representations, which show a small and apparently constant amount over the forecast horizon. Likewise, distributed generation is primarily discussed in general terms. Both IRPs anticipate slowing growth based on results from an econometric model, but the details are not provided.

Supply Side

Technology Costs:

The assumptions used by TEP and UNSE are generally reasonable and are shown in Figures 13-15. Capital cost assumptions for solar, wind, and storage all reflect future cost declines that are consistent with commonly used industry benchmarks, such as NREL Annual Technology Baseline (ATB) and Lazard. The capital cost assumptions are all significantly lower than the NREL ATB in absolute terms, with the solar capital costs particularly low. Given the history of renewable costs declining faster than most historical forecasts anticipated, the low capital costs assumed by TEP and UNSE are appropriate. However, the levelized cost of energy listed for solar and wind resources appears to be significantly higher than typical PPA prices available in the region, which are in the low $20s per MWh. Given the potential for extensions of the investment tax credit (ITC), extension of the ITC to standalone storage, and safe-harbor provisions that allow resources coming online in later years to still qualify for earlier (higher) levels of the ITC, PPA prices will likely continue to be low when UNSE begins procuring resources. Ascend recommends that the commission ensure that all ownership structures are considered during resource procurement processes, with ownership-agnostic, least-cost options being pursued.

An additional note on technology costs is that the TEP and UNSE IRPs present cost assumptions for different resources in terms of the levelized cost of energy (LCOE) in Charts 26-30 of the TEP IRP and Tables 14-16 and Charts 14-16 of the UNSE IRP (shown here in figure 16). However, LCOE is a misleading metric, because it requires an assumed capacity factor for each resource, which may not reflect actual dispatch for thermal resources. LCOE also does not account for the different grid needs that are served by different resources. For example, for a peaking resource that operates infrequently, the capital cost is a more important metric than the LCOE, while for a resource that provides a large amount of energy, year-round LCOE may be more appropriate. Additionally, because storage does not generate energy at all but rather serves as a capacity resource, LCOE is an entirely inappropriate metric, and leads to counterintuitive outcomes such as implying that 8h storage is lower cost than 4h storage when it actually is ~70% more expensive.

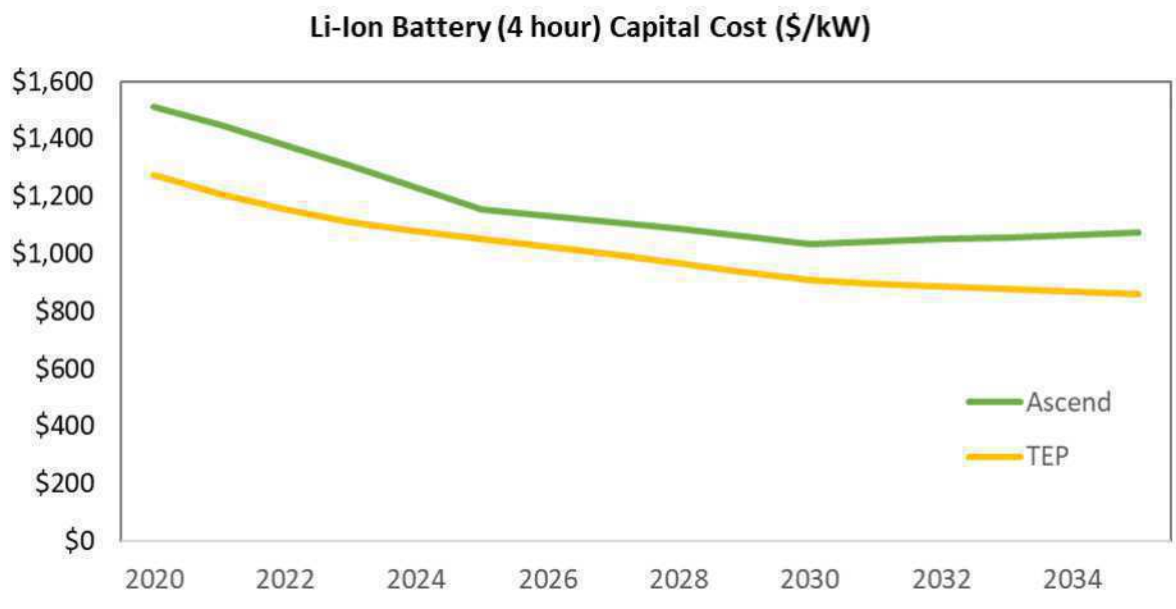


Figure 13: Capital cost comparison (li-ion 4-hour battery)

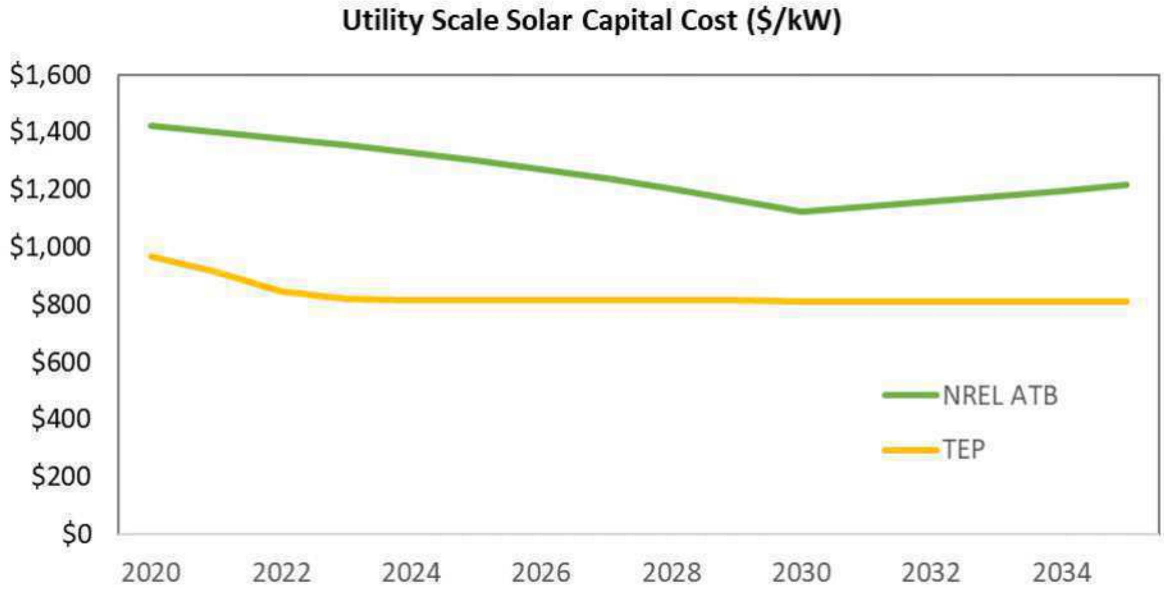


Figure 14: Capital cost comparison (utility scale solar PV)

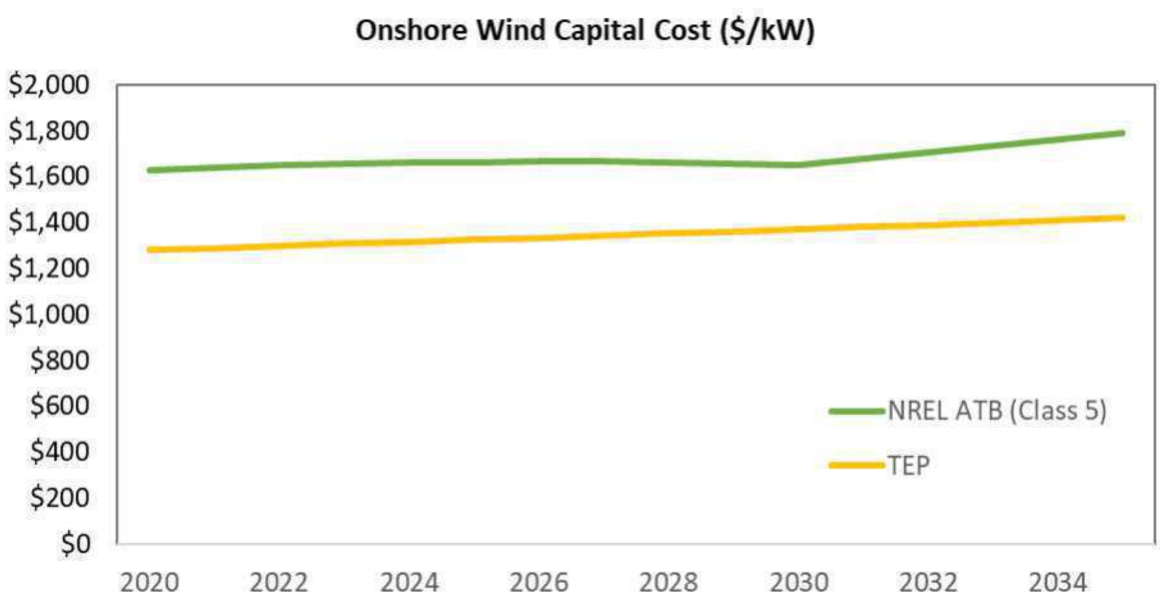


Figure 15: Capital cost comparison (onshore wind)

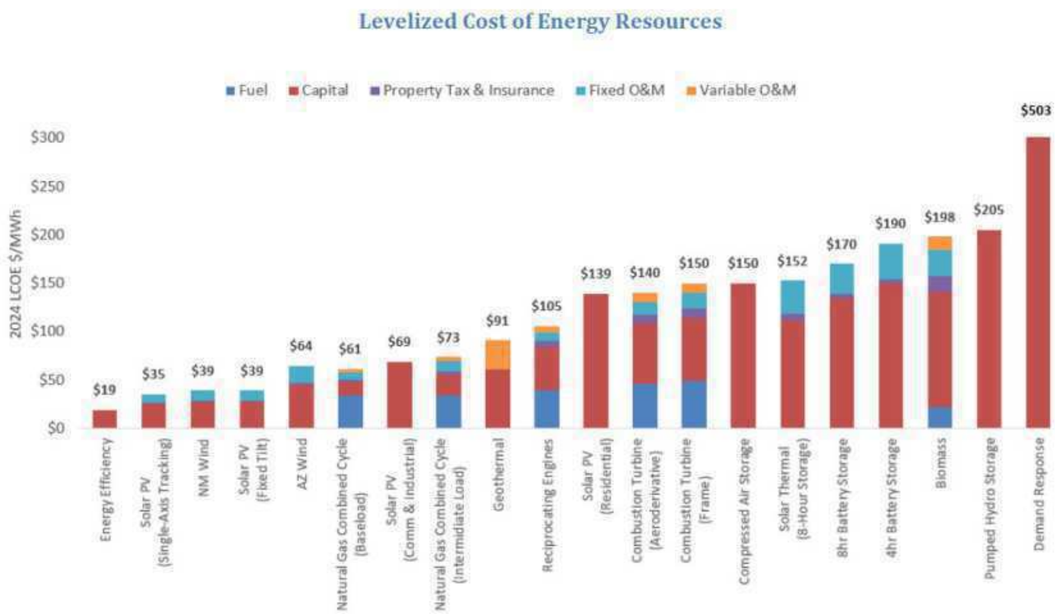


Figure 16: TEP IRP Levelized cost of energy per resource

Market Price Assumptions:

Market assumptions include power prices, gas prices, and market implied heat rates (power prices divided by gas prices). Implied heat rates function like a normalized power price that accounts for the impact of gas prices and are an indicator of whether gas generation resources can operate profitably in the market. As renewable energy sources contribute increasing shares of the electricity supply, they drive three critical changes in price dynamics. First, renewable energy with near-zero variable costs shifts the entire supply stack, leading to price depression. Second, this price depression is concentrated in hours with high renewable generation, leading to concentrated price depression during solar generating hours. Third, renewable intermittency leads to increasing price volatility, which creates value for flexible generation resources and risk for inflexible ones that are unable to quickly ramp or turn on/off in response to changing prices.

Figure 17: Palo Verde annual power price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 18: Palo Verde monthly power price comparison

(End confidential information)

The TEP and UNSE Palo Verde (PV) power prices take an hourly shape from E3 and scales it to a monthly price forecast that starts with the monthly market forwards from the Tullet Prebon index, which are then scaled by the Wood Mackenzie long-term price forecast for PV. While the incorporation of a price shape is critically important for long-term forecasts in an era of growing renewable penetration, the use of a price shape from a different vendor than the source of long-term forwards can lead to inconsistencies in the forecast. One result of this is that the implied heat rates are extremely high during non-solar hours in March (see Chart 31 of the TEP IRP and Chart 17 of the UNSE IRP), sitting at roughly 25 MMBTU/MWh while current off-peak heat rates are closer to 10, which is close to the heat rate of a typical new natural gas combustion turbine (NGCT). The implied heat rates are also high in general, staying between 15-20 MMBTU/MWh throughout the forecast, ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. These high heat rates may lead to overvaluing gas generation resources by overestimating their potential for market sales and overestimating their savings relative to market purchases. Such an overvaluation may shift the relative economics of gas capacity resources relative to storage or demand-side alternatives.

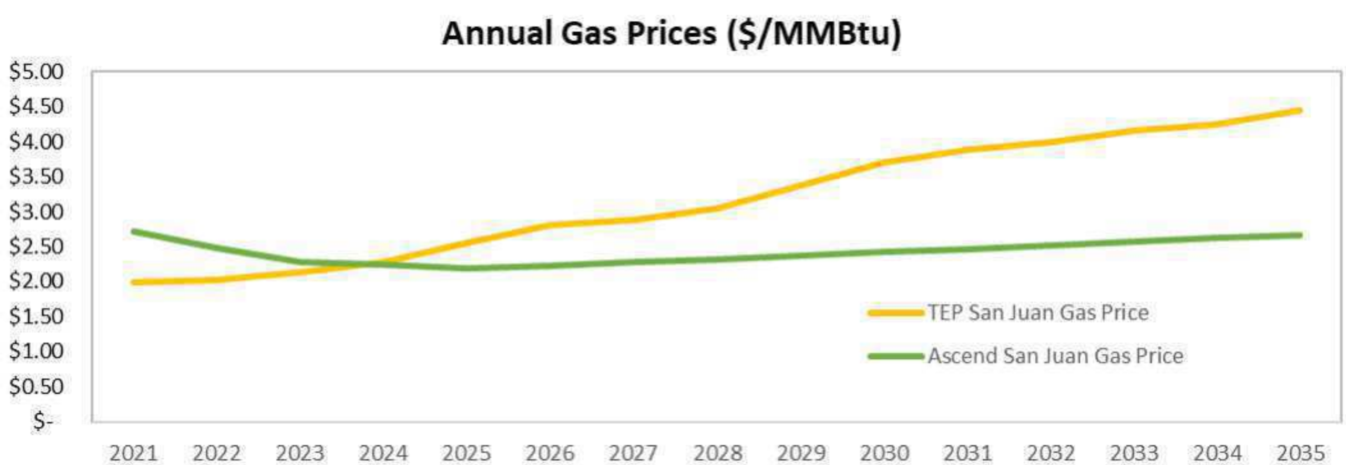


Figure 19: San Juan annual gas price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 20: San Juan monthly gas price comparison

(End confidential information)

The TEP and UNSE power prices are also high in general, climbing continuously throughout the forecast period, whereas Ascend's and APS's power price forecasts stay relatively flat in nominal terms. This high-power price forecast may lead to overvaluation of renewable resources, which could lead to a suboptimal procurement particularly of solar capacity as surplus solar generation continues to be built elsewhere in the Southwest US. With the climbing prices in TEP/UNSE's forecast, solar would appear economic throughout the forecast period, when it is likely to cease to be economic as the region becomes oversupplied during daylight hours.

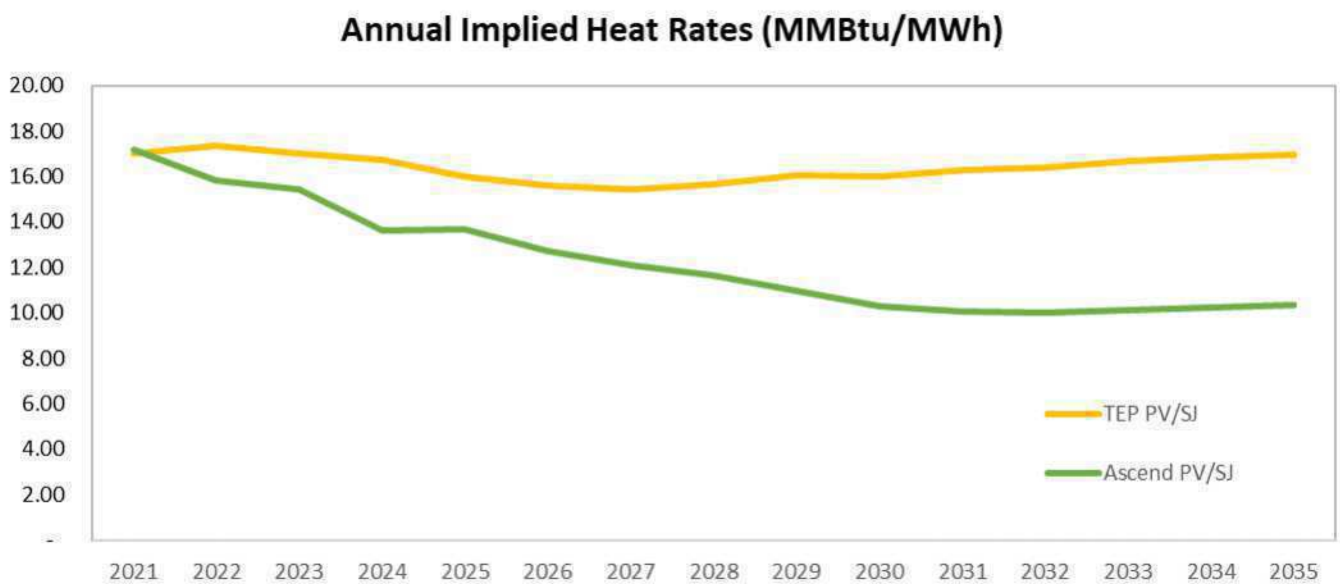


Figure 21: Annual implied heat rates, calculated as power price in Palo Verde divided by gas price in San Juan

(Begin confidential information)

[Redacted due to confidentiality]

Figure 22: Monthly implied heat rates, calculated as power price in Palo Verde divided by gas price in San Juan

(End confidential information)

(Begin confidential information) *[Redacted due to confidentiality]* ***(End confidential information).*** The assumed carbon prices are reasonable given the lack of a national or state carbon market for Arizona, reflecting the uncertainty of potential futures with and without a carbon price.

3.4.3 MODELING APPROACH

Demand Side

For the demand side, the modeling approaches consisted primarily of the methods used to develop the energy and demand forecasts. TEP's and UNSE's IRPs do have some information on the forecasts, but the important details are presented in a supplemental load forecast update. This update applied to both TEP and UNSE, as they share the same forecast methods.

Overall, the methods described are indicative of a quality forecasting approach. They conform to a variety of standard industry practices, each appropriate for its respective sector. The residential and commercial sector forecasts are based on a combination of a use-per-customer forecast and a customer forecast, each relying on ARIMA models with exogenous variables. The two forecasts are multiplied to generate the total sales. While not the most common approach, this hybrid method helps the utilities better isolate the account for how energy efficiency and distributed generation influence net retail sales versus gross consumption. The customer forecasts assess a variety of models using intuitive drivers (e.g. population, commercial establishment growth) and accounts for weather and calendar effects. Final model selection considers the out-of-sample performance of the candidate models. For these load forecasts, the IRP relied on a variety of reliable sources for their data, including IHS Global Insight, The University of Arizona Forecasting Project, Arizona Department of Commerce, the U.S. Census Bureau, and the National Oceanic and Atmospheric Administration (NOAA).

Peak demand is forecasted using a model that combines weather and sales data to estimate the peak demand. While this approach has worked well historically, a potential future shortcoming in this approach is an inability to anticipate how demand side resources might shift both the magnitude and timing of peak demand. The peak demand forecast provides little information on the typical timing of system peaks, and thus there is not sufficient data to determine how relevant this might be for these two utilities.

For energy efficiency, demand response, electrification, and distributed generation, there was no information provided on the modeling approach and the assumptions used to generate the forecast presented in the IRP or in other supporting documents from the data request.

Supply Side

The portfolios presented in the TEP and UNSE 2020 IRPs were hand-designed with the energy rules draft in mind, and in the case of UNSE with the intention to reduce reliance on market purchases of capacity. Capacity expansion models were not used for resource selection and the team hired Siemens to run the reliability analysis of these portfolios, which was based on the ability of the portfolio to meet four criteria:

- Supply sufficient energy at the net peak load
- Meet 3-hour ramp requirements
- Meet 10-minute ramp requirements
- Minimize overgeneration from renewable assets

Siemens ran Monte Carlo simulations of the combined TEP and UNSE system to determine the maximum net load as well as maximum 3-hour and 10-minute net load ramps. These results were then compared against the portfolio's firm generation and ramping capabilities. However, the reliability study did not simulate forced outages (instead just derating the thermal generation) or consider available battery state of charge and consecutive hours at high net load. These factors play a critical role in understanding reliability in a renewable/storage-heavy portfolio, and their exclusion will likely lead to designing portfolios that are less reliable in operation than they are in the model.

TEP provides a qualitative discussion of the ancillary services in Chapter 3. The modeling done by TEP in the IRP process included operating reserves equal to 6.5% of firm load but did not include intra-hour products such as frequency or regulation. The UNSE IRP does not discuss ancillary services except to say that ancillary services are provided by TEP through becoming part of the TEP balancing authority.

TEP and USNE did not model sub-hourly dispatch of their generation as part of the IRP modeling. Though both IRPs discuss participation in the CAISO Energy Imbalance Market (EIM), such future or potential participation is not incorporated in the IRP modeling.

Best-practice in resource planning involves optimized capacity expansion models that select the most economic resources subject to defined constraints, such as emissions targets and minimum/maximum resource quantities. While the portfolios in both the TEP and UNSE IRPs were hand-designed instead of optimized, this approach was reasonable given the various requirements of the draft energy rules, the requirements of Decision 76632, and requests from the TEP and USNE Advisory Councils. Knowledge of the costs of the supply resource options and expert judgement can yield a well-reasoned portfolio, particularly when there are several prescribed requirements as in the draft energy rules.

Best-practice in resource planning also involves considering a portfolio that will be robust against a variety of unknown future conditions rather than being optimized for a single simulation or set of assumptions. The portfolio cost assessment did include portfolio costs across 50 stochastic simulations with correlated uncertainty in the load, gas prices, and power prices. TEP and UNSE both demonstrated that their preferred portfolios were consistently among the least cost portfolio across the range of simulated conditions (see Appendix D of the TEP IRP and Appendix A of the UNSE IRP). However, the simulations did not include correlations with renewable generation or forced outages, which can better identify the critical events under which the system is at its limits. The critical load balancing conditions can be very different when load and renewable generation are appropriately correlated: weather conditions that drive coincident high load and high renewable generation create very different system conditions than weather conditions with high load and low renewable generation.

Best-practices also involve considering the sub-hourly (real-time) attributes of flexible resources in assessing their value to the system. In markets with real-time price signals, such as the EIM, this value is evidenced via high price spikes when the system requires resource flexibility. Given that TEP is joining the EIM in April 2022, and UNSE may follow, the potential revenue for flexible resources should be accounted for in portfolio modeling. Batteries and RICE units, which have short startup times, high ramp rates, and no startup costs often exhibit much higher value when considering real-time grid needs rather than hourly dynamics alone. This value of flexibility is increasing as energy supplies incorporate increasing shares of renewable generation.

3.4.4 REVIEW OF TEP PREFERRED PORTFOLIO

Demand Side

Supply side resources are the emphasis of TEP's preferred portfolios. For the demand side inputs, TEP's preferred portfolio only had annual projections for the energy efficiency savings out to 2035. These series represented savings compliant with the energy rules. Beyond that, the preferred portfolio consisted of one data point of a projected peak reduction of 90 MW associated with distributed generation solar. The available data shows a flat curve and limited information about demand response throughout the forecast horizon, roughly equivalent to the 41 MW of annual reductions described in TEP's DSM plan.

Supply Side

TEP's preferred portfolio adds 1,500 MW of single-axis tracking solar, 500 MW of wind, and 1,400 MW of new 4-hour storage by 2035, while retiring Springerville 1 and 2 in 2027 and 2032 respectively. It has the Springerville units running seasonally from the mid-2020s until their retirement.

The expected portfolio solar/wind ratio of 2:1 is reasonable given the expected lower cost of solar and better alignment of solar generation with load profiles. Adding renewable generation and storage through the IRP period aligns with TEP's goal of increasing resource diversity, especially when considering the new gas generation that came online just before the start of the IRP.

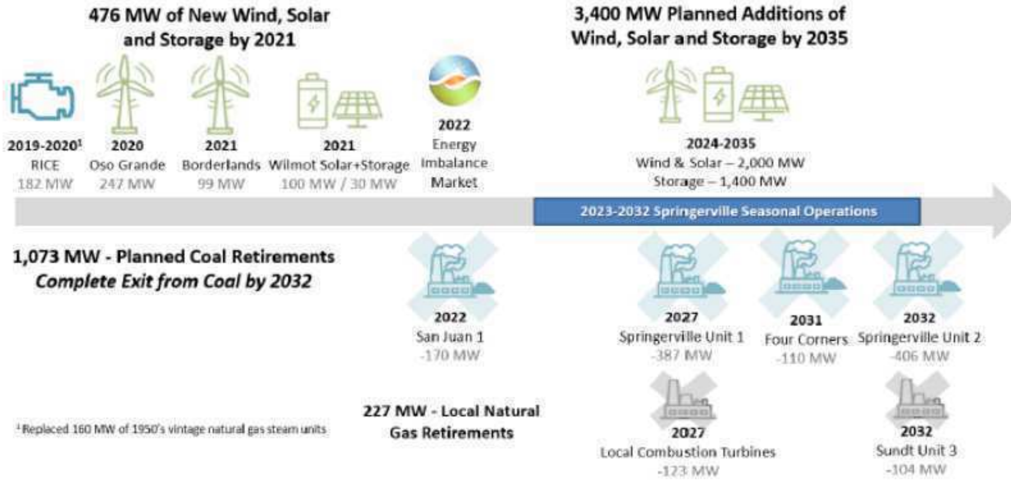


Figure 23: TEP Portfolio Evolution (Chart 56 of IRP)

3.4.5 REVIEW OF UNSE PREFERRED PORTFOLIO

Demand Side

UNSE's preferred portfolio focuses on supply side resources. The available data show only graphical representations of these resources (see Figure 24). While energy efficiency does show annual increases, both distributed generation and demand response are both small in magnitude and static over time. Note that originally, the UNSE believed itself exempt from the energy rules, but later provided a series of energy efficiency savings that were compliant.

Supply Side

UNSE's reference portfolio, shown in figure 24, involves keeping all existing thermal resources online while adding 150MW of solar generation, 115 MW of wind generation, 70MW of storage, 100 MW of RICE units, 4% annual growth in demand response, and growth in energy efficiency consistent with the draft energy rules.

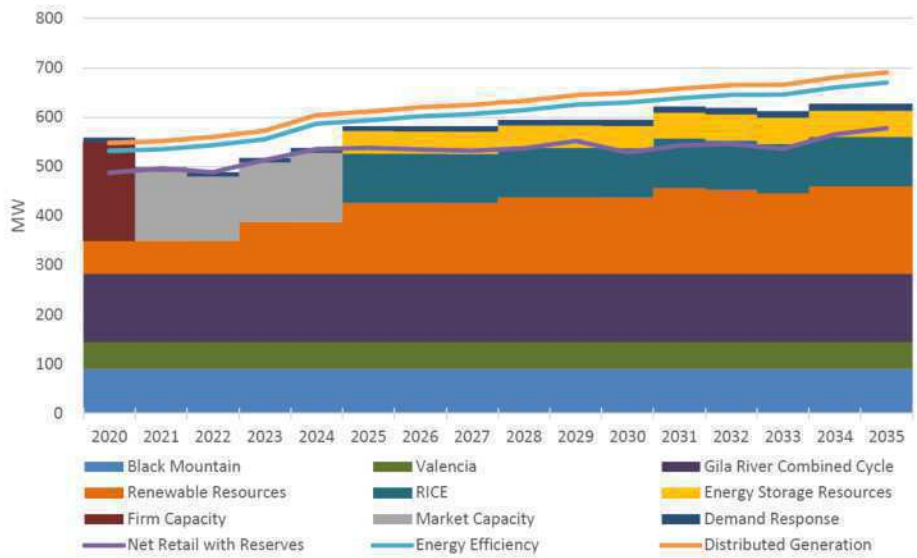


Figure 24: UNSE Preferred Portfolio Capacity Mix (Chart 35 in IRP)

Given UNSE's goal of moving toward less reliance on market capacity, the reference portfolio is a reasonable path forward. The bulk of the new supply resources are expected to be renewable energy and energy efficiency, while the capacity additions that serve reliability needs are flexible resources that are the appropriate complement to a rapidly increasing renewable penetration. The expected portfolio solar/wind ratio of 2:1 is reasonable given the expected lower cost of solar and better alignment of solar generation with load profiles. Figure 25 shows renewable energy supplying roughly half of net demand in 2035, and the RICE and storage units have the requisite flexibility to accommodate the intermittency of renewables. Additionally, UNSE's current shortage of capacity creates a need to acquire firm capacity, justifying the larger quantity of RICE units than storage. UNSE should continue to monitor the economic outlook for the Gila River NGCC, as its economic viability is likely to decline if its capacity factor declines with market prices and increasing shares of energy generation coming from low-cost renewable sources.

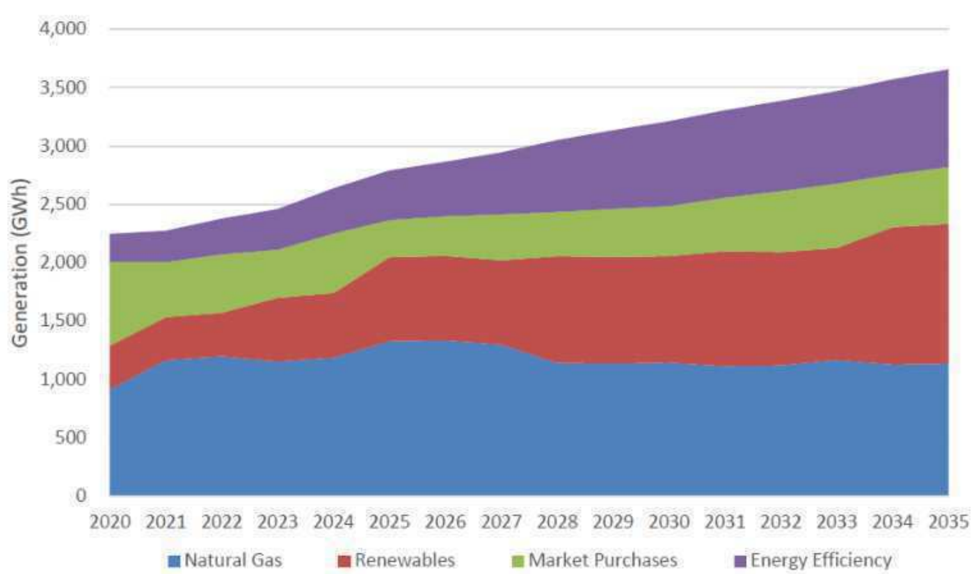


Figure 25: UNSE Preferred Portfolio Energy Mix (Chart 34 in IRP)

Because actual acquisitions will be pursued through an all-source RFP, the mixture of solar and wind supply should be adjusted as future resource costs evolve, opportunities emerge to procure refurbished firm capacity resources at low costs, and additional energy efficiency gains may become prohibitively expensive as energy codes become more rigorous and low-hanging-fruit opportunities diminish. UNSE should also continually assess its needs relative to the market and focus on procuring resources that complement the existing supply in the region. For example, if the region becomes oversupplied with solar generation independently of UNSE, UNSE should consider increasing its acquisitions of storage or wind instead. Thus, while the reference portfolio is a reasonable path forward given current market conditions and expectations, new resources should be strategically acquired in reflection of the evolving supply conditions and market context in Arizona in general.

3.4.6 RECOMMENDATIONS TO IMPROVE IRP

Demand Side

While the content of the IRP is generally reasonable, the primary opportunity for improvement for both TEP's and UNSE's IRPs would be additional granularity to the reported data and more supporting documentation for the data and methods used to create the demand side resource values. Only the energy and peak demand forecasts had a supporting document that clearly outlined the data and methods, but it would be helpful to have similar documentation of the efforts to develop data for the other resources.

One example of how the data provided lacked important granularity was the load growth due to electrification. Ignoring that EVs were the only explicitly considered source of load growth, the only information was an annual total kWh value. To understand this forecast and extend it to 2050, the analysis would have been improved with more information on the underlying assumptions, such as the number of vehicle or customers and the annual consumption per vehicle. Furthermore, there was no information to break out whether the energy was due to residential customers or commercial fleets.

Another area that would have benefited from more details was energy efficiency. In general, a better understanding of the measures or end uses contributing to the savings would help to create better estimates of peak impacts and costs. Furthermore, one of the series of energy efficiency savings provided as part of the response to the data request was inclusive of distributed generation, further complicating efforts to assess the inputs. These data were likely provided in TEP's and UNSE's energy efficiency potential studies, but this report was not available.

Finally, given the uncertainty with forecasting in general, it is understandable that the IRP forecasts did not go to 2050. Nevertheless, had the original forecast been extended 15 years, it would have at least ensured consistent forecast drivers throughout forecast horizon. Likewise, based on the relatively incongruent historical and forecasted growth rates, it would have been helpful to have more information to better understand the drivers underlying this inconsistency.

Supply Side

TEP and UNSE should begin accounting for sub-hourly value of their resources. Accounting for the needs for and value of real-time flexibility is becoming increasingly important in resource planning as renewable penetrations grow and volatility increases in both supply and net demand. Resource planning that only considers hourly time intervals increasingly obscures the sub-hourly dynamics that both create economic costs/revenues and also lead to supply shortages. Given that TEP is joining the EIM in April 2022, and UNSE may follow, resource procurement must account for the value that flexible resources provide at the sub-hourly level in this market. This value can be accounted for either by simulating real time prices and dispatch, or by calculating a 'sub-hourly credit' that varies across resource types according to their flexibility and accounts for this flexibility value.

TEP and UNSE should study resource adequacy, reliability, and loss of load conditions in greater depth. Resource planning in an era of high renewable penetrations must account for the influence of weather on loss-of-load events. Accounting for correlations between weather, load, renewable generation, and forced outages is critical for identifying the critical conditions under which net demand peaks. Moreover, as solar generation is increasingly added to the system, the net load peak shifts towards sunset, leading to a near-zero capacity value for solar generation. To properly account for these conditions, reliability studies should at a minimum simulate forced outages, correlated load and renewable generation, and storage state of charge to assess Loss of Load Hours (LOLH) or Loss of Load Events (LOLE) and calculate the Effective Load Carrying Capability (ELCC) of different resources that are added to the portfolio. Planning using a simple reserve margin and capacity targets will become increasingly insufficient as the TEP and UNSE portfolios become increasingly supplied by renewable and duration-limited (i.e. storage) resources. Planning must focus on procuring the resources that meet the critical needs for the system and when those critical conditions occur.

TEP and UNSE should implement optimization software in its capacity expansion planning. While hand-designed portfolios can be appropriate for meeting a complex set of constraints, such as meeting the draft energy rules, the changing dynamics of market prices, the value of energy, and net load shapes make it increasingly difficult to hand-design portfolios that will be optimal for a changing and evolving future. A capacity expansion approach that automatically optimizes resource acquisition subject to specified constraints should be implemented in future planning activities.

TEP and UNSE should consider using a model which simulates weather, load, and market prices. Power system operations are heavily dependent on weather which drives the load, renewable generation, and market prices. TEP and UNSE should consider using a model that uses weather to simulate load, renewable generation, and market prices. TEP and UNSE are on a path to a high level of renewable energy; they should consider modeling tools that can realistically replicate the dynamics of a high renewables system.

4 Assessment of Proposed Energy Rules Cost

The following sections detail a cost analysis of the proposed Energy Rules, with targets of 100% and 80% clean energy by 2050 as well as a "least cost" case. The results show a comparison of the total costs of the "Energy Rules" cases minus the "Least-Cost" case. Costs include new capital expenditure, operating expenses, fuel, purchased power, stranded costs, and transmission access costs.

The "Least-Cost" portfolio is not easy to define without the time to perform a full capacity expansion analysis. In hand-designing the portfolios, we interpreted the "Least-Cost" portfolios as having the implicit assumption that traditional resources such as natural gas power plants are "least-cost" for providing firm capacity. Therefore, our "Least Cost" portfolios follow a more traditional approach to resource acquisition, which includes natural gas turbines for capacity, less energy efficiency savings in the future (as cost-effective EE gets harder to find and implement), and more renewables. Any portfolio without GHG constraints would still add renewable energy because it is now widely considered the least-cost source of bulk system energy. In contrast, the "Energy Rules" portfolios do not add new gas but instead rely on storage and renewables to replace retiring coal and gas. For the 100% clean energy portfolio, existing gas infrastructure were converted to burn renewable fuels such as green hydrogen between 2040 and 2050.

The analysis was performed by the utilities themselves with the production cost model Aurora. Although Aurora has a capacity expansion capability, we did not request the utilities use it because capacity expansion modeling requires a significant time investment in the specification of constraints, analysis, and re-running of the model to get the results. Although APS used capacity expansion modeling in their process, TEP and UNSE hand-designed portfolios and were not immediately set up to perform capacity expansion modeling.

4.1 APS

4.1.1 APPROACH

APS estimated the cost of implementing the Energy Rules by calculating the revenue requirements for a least cost scenario, a scenario where APS meets the 80% carbon reduction target by 2050, and a scenario where APS eliminates all carbon emissions by 2050. The least cost scenario provided a reference case to benchmark the Energy Rules costs. APS used the Technology Agnostic portfolio from the IRP, extended to 2050, as the least cost scenario for the Energy Rules analysis. The Shift portfolio provides the basis to build the Energy Rules 80% and Energy Rules 100% portfolios. To meet the 80% carbon emissions goal by 2050, APS made minor adjustments to the Shift portfolio since it was found to reduce emissions 77% by 2035. The Energy Rules 100% portfolio had significantly more clean energy and energy storage additions to reach full decarbonization by 2050. APS ran the three scenarios with the same inputs and assumptions used in the IRP and also using custom inputs provided by Ascend that specified alternative projections for gas and power market prices and technology costs.

In extending the models to 2050, APS performed reliability checks and made necessary adjustments to ensure the portfolios could adequately serve customer load. APS did not run a new resource adequacy model on the portfolios, instead they used previous modeling outputs to estimate the capacity contribution of future wind, solar and battery storage resources. Given the time constraints, this approach seemed satisfactory for the models.

Finally, APS ran a small set of sensitivity runs to determine how the assumed prices of natural gas and carbon emissions would change the outputs.

4.1.2 INPUTS AND ASSUMPTIONS

Demand Side

The assessment of the energy rules necessitates developing forecasts for base load and peak demand, as well as other demand side resources such as energy efficiency, demand response, and distributed generation. This entailed reviewing various data sources and leveraging existing studies to extend the forecast to 2050. The remainder of this section describes the creation of these series.

APS Base Forecast: In the available data, the energy forecast for APS increases from 28,905 GWh in 2020 to 47,448 GWh in 2035. The annual growth rate between 2020 and 2021 is approximately 4.1%, falling to 2.5% between 2034 and 2035. The annual growth rate in the APS baseload forecast is 2.5% between 2034 and 2035. The base forecast of energy from 2036 to 2050 assumes the 2.5% growth rate continues, with the 2050 base forecast of 68,718 GWh. As stated previously, the forecast was reviewed by Itron, and then further updated by APS to improve the IRP forecast.

The base forecast for peak demand shows growth from 7,470 MW in 2020 to 11,271 MW in 2035. The annual peak demand growth rate in 2020 is 2.41% substantially lower than the energy forecast. The annual peak demand growth rate between 2034 and 2035 is 2.37%, very similar to the 2020 peak demand growth rate and the energy growth rate during this period. The annual peak demand growth rate between 2034 and 2035 is 2.37%.

APS Electrification: The electrification data provided by APS included base, transformative, and blended EV adoption scenarios. The APS EV forecast for 2019 estimated annual usage at 40 GWh growing to 56 GWh in 2020. The APS EV usage is forecast through 2038, where annual usage if forecast to be 1,714 GWh. Verdant assumed that the 40 GWh was in the base usage forecast and began the 2020 base forecast for EV and electrification usage at 8 GWh. For 2038, the Verdant EV and electrification forecast is slightly higher than APS's original forecast. APS's forecast was 1,715 GWh while the Verdant base forecast is 1,815 GWh. Both forecasts project an addition of over 300,000 EVs from 2020 to 2035. The growth rate in electrification energy use exceeded 100% during the early 2020s, declining to under 20% by 2035. Verdant assumed a continued growth in EVs, forecasting more than one million EV in APS territory by 2050, with an energy consumption of 4,805 GWh. The extrapolation of these data to 2050 was more challenging given the high degree of uncertainty regarding EV adoption.

APS Energy Efficiency: APS's IRP did not include the required forecast of energy efficiency savings consistent with the Energy Rules. The APS 2021 DSM plan, however, has a target of approximately 335,000 MWh of annual energy savings from efficiency measures while the APS Energy Consumption by Month and Customer Class listed an incremental 2021 energy efficiency program saving of approximately 175,000 MWh. The targeted energy savings in the 2021 DSM plan, closely approximates the energy efficiency savings necessary to meet the aggressive energy rule targets. Given the difference in the two 2021 incremental energy efficiency values, they were used as the basis for two different energy efficiency forecasts. The higher 2021 value was used to develop a forecast of energy efficiency savings for the Energy Rules portfolio while the lower 2021 value was used for the Low-Cost portfolio. The energy efficiency for both the energy efficiency rules and the low-cost portfolio begin with the IRP's initial forecast of 210,664 MWh of energy efficiency savings in 2020.

For the Energy Rules energy efficiency forecast, the incremental energy efficiency savings grow at the same rate as the base energy forecast. This approach maintains the required relationship between energy efficiency savings and the base energy forecast. The cumulative energy efficiency savings recognizes that approximately 20% of APS energy efficiency savings are derived from behavioral programs with a one year expected useful live. While it is assumed that APS continues to offer these programs, the accumulation of savings assumes that the behavioral savings from the previous year program are not maintained. In the Energy Rules scenario, the cumulative energy efficiency savings are 5,318 GWh in 2035 and 12,028 GWh in 2050. The Low-Cost portfolio cumulative energy efficiency savings are 2,836 GWh in 2035 and 5,461 GWh in 2050. The Low-Cost portfolio savings are consistent with APS's IRP plans and reflect incremental energy efficiency savings of 175,000 MWh annually.

The energy efficiency demand savings for the Energy Rules and the Low-Cost portfolio were developed similar to the energy savings. The 2020 demand savings for both portfolios begin with the 2020 IRP number, 105 MW. In 2021 the Energy Rules portfolio uses the incremental demand savings from the 2021 DSM plan, 132 MW for a 2021 cumulative demand savings of 216 MW. The Low-Cost portfolio cumulative demand savings in 2021 is 189 MW. In 2035 the Energy Rules demand savings are 2,006 MW, growing to 4,484 by 2050. The Low-Cost portfolio demand savings are forecast at 1,207 in 2035 and 3,098 in 2050.

APS Demand Response: The demand response programs are assumed to have demand savings but no energy savings. In 2020, both the energy rules and the low-cost portfolio have 21 MW of demand response savings. These savings are consistent with those presented in the bridge portfolio. For the Low-Cost portfolio, the demand response program follows the trajectory of the bridge portfolio, growing to 337 MW in 2035. The Energy Rules portfolio has a larger increase in demand response between 2020 and 2021 due to the planned demand response savings in the 2021 DSM plans. The 2021 demand response savings in the Energy Rules portfolio is 116 MW compared to 62 MW in the least cost portfolio. For the low-cost portfolio, the demand response program follows the trajectory of the bridge portfolio, growing to 337 MW in 2035. The Energy Rules portfolio has a more rapid increase in the early years of the forecast period (representing a significant increase in DR programs in 2021), but this portfolio also grows to 337 MW in 2035. The Energy Rules portfolio grows to 691 MW in 2050 while the Low-Cost portfolio grows slightly less to 608 MW.

APS Distributed Generation: For both energy rules and low-cost scenarios, distributed generation series are based on the bridge portfolio. The energy and demand savings in 2020 are 192 GWh and 4 MW. These are projected to grow to 2,670 GWh and 225 MW by 2035. These are projected to grow to 2,670 GWh and 225 MW by 2035. The 2050 savings represent a linear extrapolation of savings reaching 5,535 GWh and 633 MW.

Supply Side

APS used the Technology Agnostic model for its least cost reference in the analysis of the Energy Rules. For the carbon reduction cases, 80% and 100% reduction, APS used the Shift portfolio since this portfolio achieved nearly 77% carbon reductions in 2035 putting it on a path to reach 80% reduction by 2050. APS also used the Shift portfolio as a starting point for the 100% carbon reduction by 2050 scenario. The table below shows the portfolio capacity by resource type. The Energy Rules portfolios rely much more on renewables and energy storage while the least cost portfolio adds a lot of natural gas capacity. APS used the same portfolios for the APS and Ascend assumptions.

Table 4: APS Portfolio Capacity by Resource Type – Both APS and Ascend Assumptions

	Least Cost			**Energy Rules 80%**			**Energy Rules 100%**		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Natural Gas	6,923	9,093	11,807	4,933	5,295	4,730	4,933	5,295	-
Coal	970	-	-	970	-	-	970	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Solar	717	1,549	2,645	2,417	6,024	9,120	2,417	7,074	7,570
Wind	647	600	2,250	1,597	2,400	4,300	1,597	2,600	3,300
Geothermal	-	-	-	-	-	250	-	-	250
Biomass	3	-	-	3	-	-	3	-	-
Storage (4 hours)	552	1,400	1,850	1,702	3,550	3,400	1,702	3,550	5,000
Storage (8 hours)	-	-	-	-	1,250	1,250	-	1,250	5,000
Storage (12 hours)	-	-	-	-	200	3,500	-	1,000	3,500
Microgrid	263	313	313	88	163	163	88	163	163
Market Purchases	160	160	160	160	160	160	160	160	160
Renewable Fuels	-	-	-	-	-	-	-	-	4,706

As expected, the carbon emissions drop considerably for the two Energy Rules portfolios.

Table 5: CO_2 Emissions in millions of metric tons

	2030	**2040**	**2050**
Least Cost	12.4	10.9	12.9
Energy Rules 80%	9.1	3.8	2.2
Energy Rules 100%	9.1	2.7	0

Carbon emissions in 2005 were 16.6 million metric tons which is the reference year for the 80% reduction goal. The carbon emissions in 2050 with the updated Energy Rules must be less than 3.32 million metric tons. APS modeling shows the Shift portfolio extended to 2050 can achieve 86% reduction.

4.1.3 RESULTS

The cost of transitioning to a clean energy system was determined by the increased revenue requirement for the clean portfolio compared to the least cost portfolio. As the following charts indicate, the cost to achieve a fully decarbonized grid is much higher than the 80% reduction scenario. However, cost estimates beyond 2030 are very speculative and should be taken as rough estimates. Technological advances in energy storage will be an important driver in costs for future grid operations, and at this point, energy storage is rapidly changing.

The results of the analysis for APS are shown in the following tables:

Table 6: Revenue Requirement ($M) - Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	2,865	3,419	3,831	4,294	7,342
80% Clean	2,865	3,419	3,832	3,919	5,657
Least Cost	2,796	3,118	3,272	3,307	4,650
Difference (100% Clean – Least Cost)	69	301	560	987	2,692
Difference (80% Clean – Least Cost)	69	301	560	612	1,008
% Difference (100% Clean – Least Cost)	2%	10%	17%	30%	58%
% Difference (80% Clean – Least Cost)	2%	10%	17%	19%	22%

Table 7: Revenue Requirement ($M) - Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	2,714	3,472	3,969	4,738	7,952
80% Clean	2,714	3,472	3,969	4,410	6,193
Least Cost	2,613	3,164	3,436	3,789	5,545
Difference (100% Clean – Least Cost)	100	308	533	949	2,407
Difference (80% Clean – Least Cost)	100	308	533	621	648
% Difference (100% Clean – Least Cost)	4%	10%	16%	25%	43%
% Difference (80% Clean – Least Cost)	4%	10%	16%	16%	12%

Table 8: Revenue Requirement Net Present Value[5] ($M) for 2021 - 2050

	APS Assumptions	Ascend Assumptions
100% Clean	46,717	48,401
80% Clean	44,390	46,092
Least Cost	40,231	42,157
Difference (100% Clean – Least Cost)	6,486	6,244
Difference (80% Clean – Least Cost)	4,158	3,935
% Difference (100% Clean – Least Cost)	16%	15%
% Difference (80% Clean – Least Cost)	10%	9%

[5] Assumes 7% annual discount rate

Table 9: Average Rate Impacts ($/kWh) - Utility Assumptions

	2025	**2030**	**2035**	**2040**	**2050**
100% Clean	0.083	0.088	0.091	0.094	0.136
80% Clean	0.083	0.088	0.091	0.086	0.105
Least Cost	0.079	0.077	0.073	0.067	0.076
Difference (100% Clean – Least Cost)	0.0036	0.0109	0.0179	0.0274	0.0597
Difference (80% Clean – Least Cost)	0.0036	0.0109	0.0179	0.0191	0.0285
% Difference (100% Clean – Least Cost)	5%	14%	25%	41%	78%
% Difference (80% Clean – Least Cost)	6%	14%	24%	41%	74%

able 10: Average Rate Impacts ($/kWh) - Ascend Assumptions

	2025	**2030**	**2035**	**2040**	**2050**
100% Clean	0.079	0.090	0.094	0.104	0.147
80% Clean	0.079	0.090	0.094	0.097	0.115
Least Cost	0.074	0.078	0.077	0.077	0.091
Difference (100% Clean – Least Cost)	0.0044	0.0111	0.0175	0.0273	0.0563
Difference (80% Clean – Least Cost)	0.0044	0.0111	0.0175	0.0202	0.0237
% Difference (100% Clean – Least Cost)	6%	14%	23%	36%	62%
% Difference (80% Clean – Least Cost)	6%	14%	23%	26%	26%

Table 11: Average Monthly Residential Bill[6] Impacts ($) - Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	87.11	92.62	95.74	98.91	142.66
80% Clean	87.11	92.62	95.75	90.28	109.93
Least Cost	83.36	81.20	76.91	70.19	80.00
Difference (100% Clean – Least Cost)	3.75	11.42	18.83	28.73	62.66
Difference (80% Clean – Least Cost)	3.75	11.42	18.84	20.09	29.93
% Difference (100% Clean – Least Cost)	4%	14%	24%	41%	78%
% Difference (80% Clean – Least Cost)	4%	14%	24%	29%	37%

[6] Assumes *1,050 kWh monthly consumption per customer*

Table 12: Average Monthly Residential Bill Impacts[7] ($) - Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	82.51	94.07	99.18	109.13	154.52
80% Clean	82.51	94.07	99.18	101.59	120.34
Least Cost	77.93	82.41	80.77	80.41	95.40
Difference (100% Clean – Least Cost)	4.58	11.66	18.41	28.72	59.12
Difference (80% Clean – Least Cost)	4.58	11.66	18.41	21.17	24.94
% Difference (100% Clean – Least Cost)	6%	14%	23%	36%	62%
% Difference (80% Clean – Least Cost)	6%	14%	23%	26%	26%

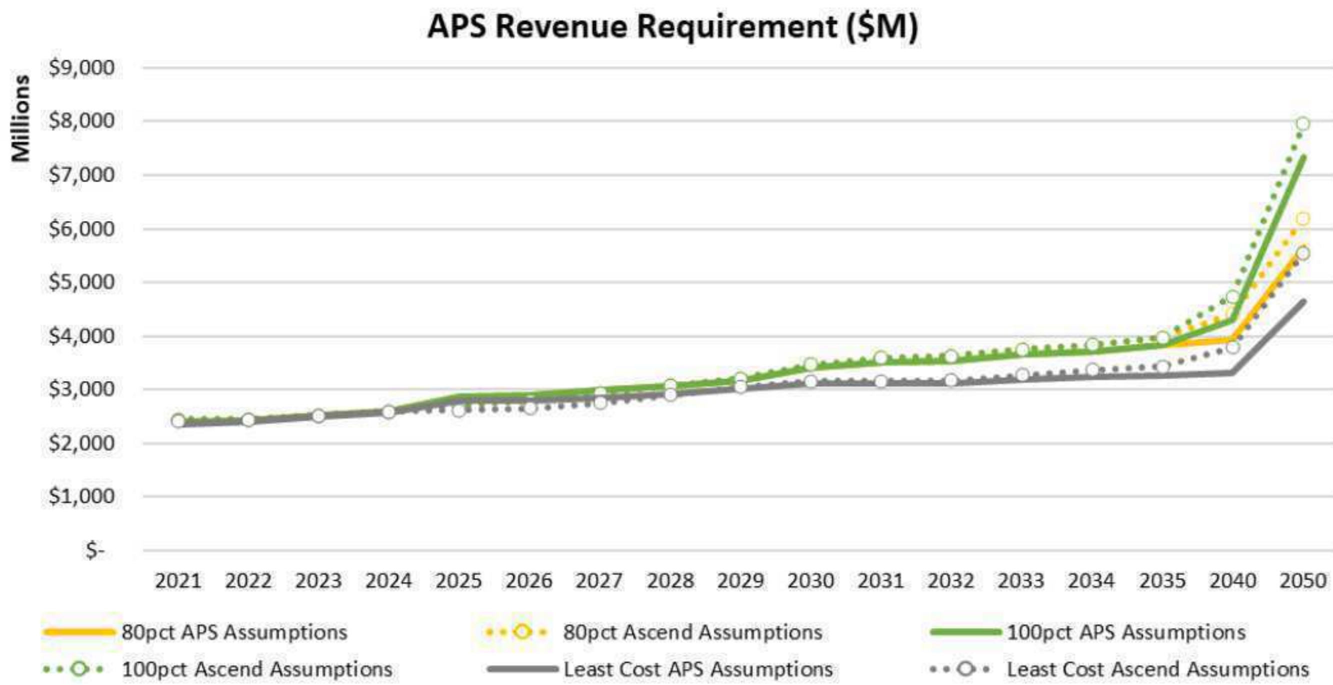


Figure 26: APS revenue requirement (including transmission expansions)

Revenue requirements are very similar in the first 15 years for both Ascend and APS assumptions. A deviation is observed in years 2040 and 2050 driven by minor differences in the assumptions. APS ELCC assumptions are reasonably aligned to Ascend's forecast, both declining over the 30 years, however Ascend's ELCC drop is slightly more aggressive resulting in additional required capacity to meet peak demand and thus slightly higher capital costs.

[7] Assumes *1,050 kWh monthly consumption per customer*

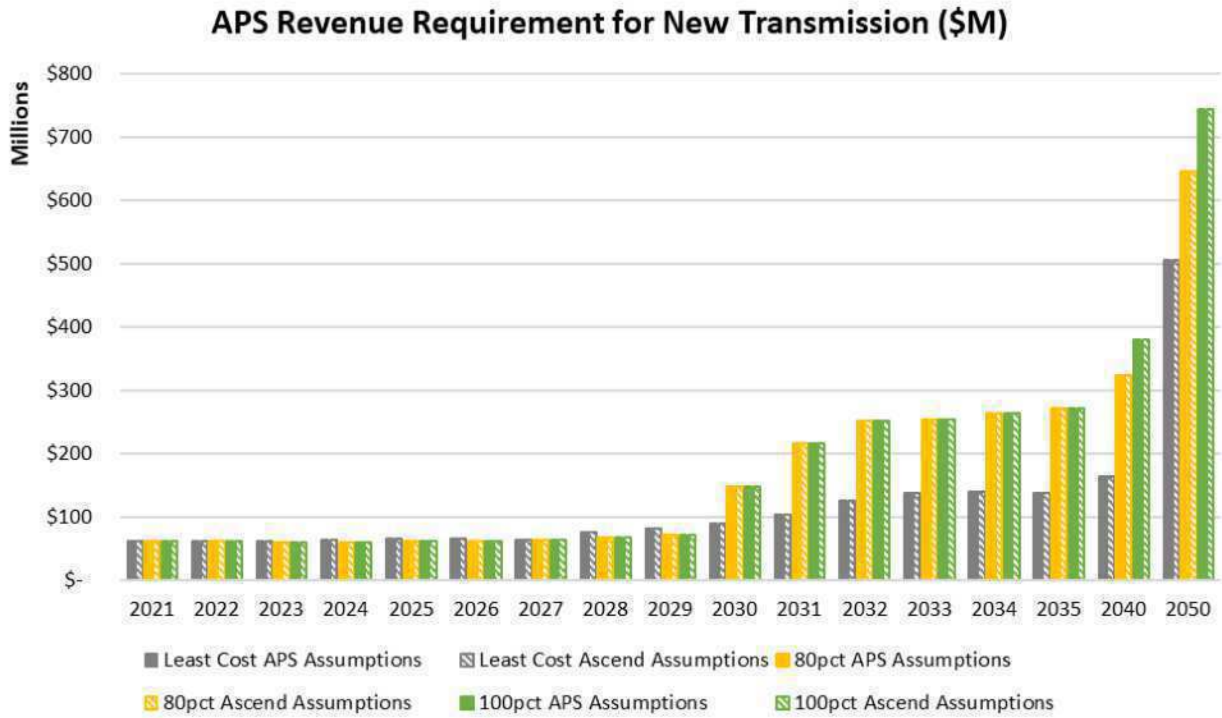


Figure 27: APS revenue requirement for new transmission

Cost of new transmission lines is one component of the overall revenue requirement. Transmission requirements are very similar across all scenarios until 2030, after which the 80% and 100% cases require significantly higher revenue requirements.

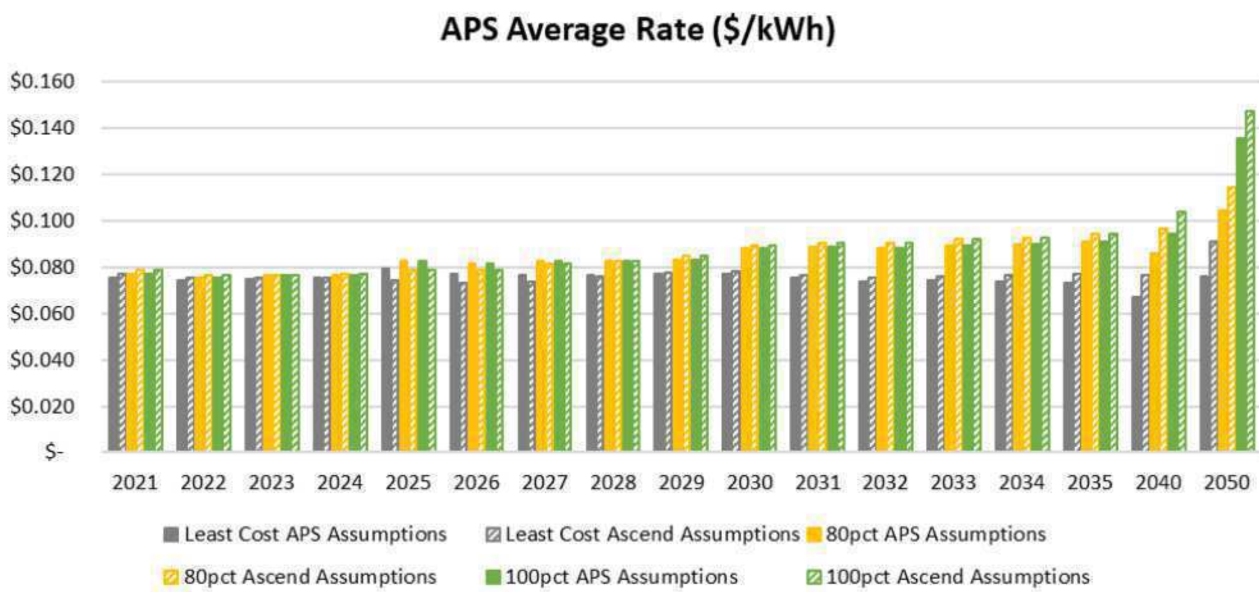


Figure 28: APS average electricity rate

The difference in average rates in the first 10 years is minimal across all scenarios and assumptions. Post 2030 the gap widens, and the "Least Cost" remains consistently cheaper than the 80% and 100% cases until 2050

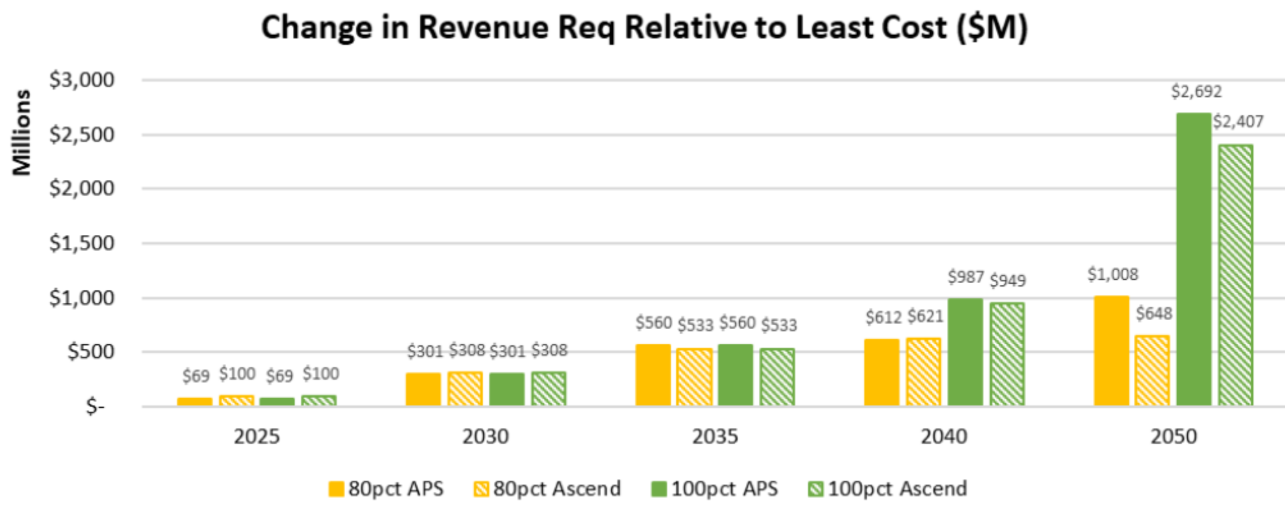


Figure 29: APS change in revenue requirement relative to the least cost scenario

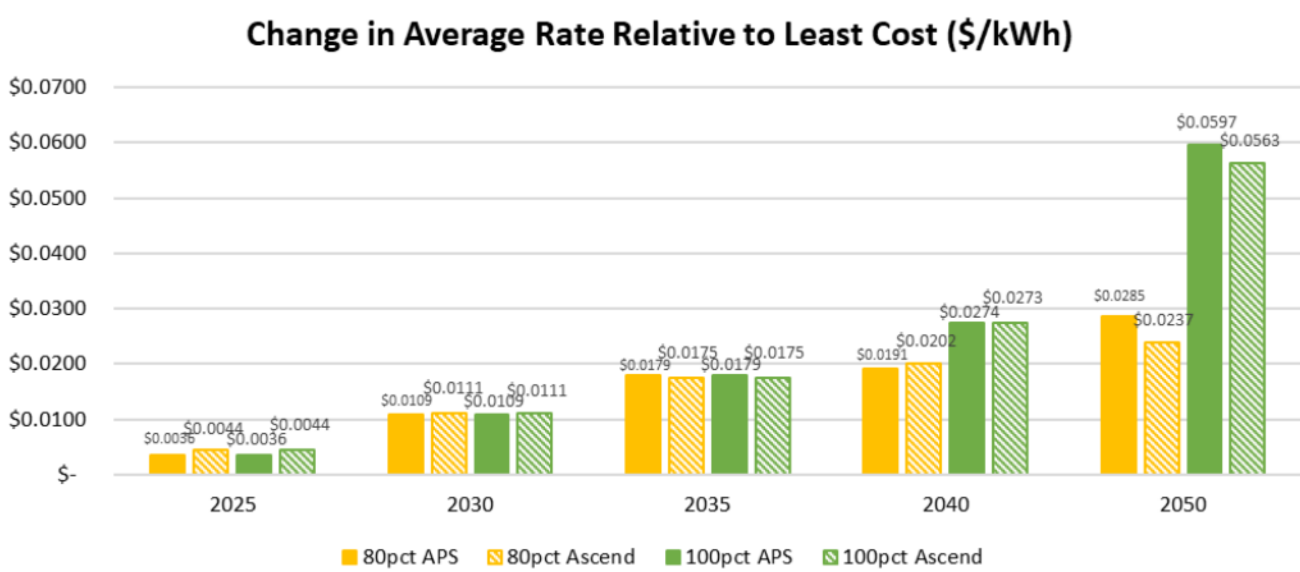


Figure 30: APS change in average electricity rate relative to the least cost scenario

Looking at the incremental difference until 2040 relative to the "Least Cost" case, the energy rules seem to have a low impact on the average rate and revenue requirement. The 100% case in 2050 has double the incremental cost than the 80% case.

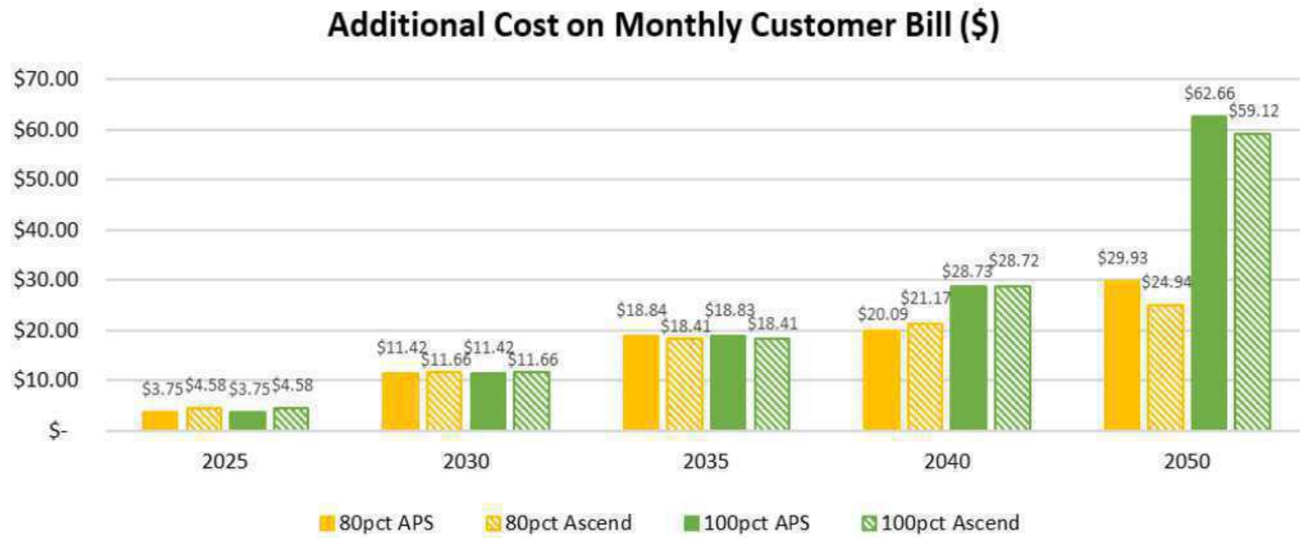


Figure 31: APS monthly additional cost on electricity bill as a result of adopting the energy rules

Calculating the customer bill based on a monthly consumption of 1050 kWh, the 80% carbon free target results in an additional cost of 25 to $30 in 2050 dollars compared to $59 to $63 in the 100% case.

Overall, the results show that the Energy Rules will have modest cost increases for the 80% target and significantly higher increases for the 100% target. As mentioned earlier these outputs rely on assumptions for future technology costs and market prices that are extremely uncertain when projecting out to 2050. Finally, the path to 80% or 100% will rely on significant investments in renewables and energy storage. There may also be a fair amount of investment in renewable fuels such as hydrogen which has yet to be commercially deployed. The Energy Rules will propel APS and others to keep on the path towards a clean energy future while they monitor developments and innovations in the energy sector to determine the best path forward.

4.2 TEP

4.2.1 APPROACH

To analyze the cost associated with the energy rules Ascend and TEP hand designed portfolios that had 80% and 100% reductions in carbon emission by 2050 as well as a least cost portfolio. The 80% and 100% reductions portfolios were setup to comply with the draft Energy Rules for both 80% and 100% reductions in carbon emissions by 2050. After creating the portfolios under both Ascend and TEP's assumptions on ELCC and market prices, the TEP resource planning staff used their production cost model to estimate the costs of each portfolio. The outputs from the production cost modeling were used to assess the cost of the Energy Rules and their impact on customer rates.

4.2.2 INPUTS AND ASSUMPTIONS

Demand Side

For both TEP, the IRP served as the foundation for analysis, but a variety of other data sources were necessary to supplement it, including the following:

- TEP 2021 DSM Plan
- TEP Load Forecast Update
- TEP Forecast Documentation
- TEP Staff Responses to Data Requests

For cases where the necessary data elements have multiple values or insufficient detail, the above sources were often bolstered by additional research and professional judgement. The remainder of this section describes the data and approaches used to develop the necessary series for this IRP review.

TEP Base Forecast: In the available data, the energy forecast for TEP increases from 8,970 GWh in 2020 to 11,721 GWh in 2035, with an average annual growth rate of 1.8%. The base forecast for peak demand shows growth from 2,589 MW in 2020 to 2,931 MW in 2035. The average annual growth rate of 0.8% is substantially lower than the energy forecast.

TEP Electrification: The electrification data for TEP consisted of a forecast of the annual energy associated with EVs, beginning with a total of 7 GWh and increasing to 786 GWh in 2035. Given the low starting point and anticipated adoption, the annual rate of this growth in these data varied greatly, starting at more than 200% per year and declining annually. The extrapolation of these data to 2050 was more challenging given the lack of detail in the data and the high uncertainty regarding EV adoption. The data provided by TEP show that by 2035, around 45% of TEPs residential customers will have an electric vehicle (assuming an annual consumption of 4,000 kWh). The application of linear extrapolation to these data would result in 65% of customers having EVs in 2050, which was deemed too low based on limited available forecasts. For TEP, the extrapolation of the starting by developing a 2050 estimate of total EV consumption based on an assumption that 80% of customers would have one EV and then filling in the series from 2035 to 2050 to represent a more typical adoption curve, with a declining rate of growth towards the end of the forecast horizon.

The peak demand for EVs assumed that most charging will occur off peak, so coincident load factor of 0.2 was applied to the energy data. Note that there was no data regarding other components of electrification and no difference in the data for the energy rules and least cost scenarios.

TEP Energy Efficiency: TEP's IRP did not include the required forecast of both energy efficiency energy and peak demand savings, so these series were derived from several sources. For the series representing savings compliant with the energy rules, the data came from a response to a data request for this IRP review. This data request included the incremental energy efficiency added annually through 2050, ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***. Because these data extended to 2050, it was not necessary to extend these series to meet the requirements. The data request also included information on the 8,760 hourly shape of the resource, which was used to convert the annual energy savings into peak demand impacts. Using the average savings from July weekdays from 4:00 PM to 7:00 PM, the energy savings translate into peak demand savings of ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***.

The least cost scenario for energy efficiency relied on data in the IRP, which includes a series of annual MW of peak demand savings associated with energy savings. These data showed peak demand savings of 1 MW in 2020 increasing to 112 MW in 2035. Using linear extrapolation, this series was extended to 214 MW in 2050. Using the same relationship between energy and demand in the energy rules scenario, this series was converted to energy savings of ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***.

TEP Demand Response: Both historically and in its forecast, TEP has only a small presence of peak demand savings from demand response. For both energy rules and least cost scenarios, the demand response series is based on the 41 MW of savings from the 2020 DSM plan – representing about 1.6% of the system peak – increasing to 57 MW in 2050. With no information in the IRP or other data sources to suggest that TEP intends to expand its DR capabilities, this is based on the same rate of growth as the base peak demand. These series were used for both energy rules and low-cost scenarios.

TEP Distributed Generation: For both energy rules and least cost scenarios, distributed generation series are based on the IRP's MW savings from 2020 to 2035, which translate to incremental peak demand savings of 3 MW in 2020 increasing to 57 MW in 2050. Using the assumption that most of these savings are due to solar, they translate into 5.3 GWh of energy savings in 2020 increasing to 123 GWh in 2050. Again, these series were used for both energy rules and least cost scenarios.

Supply Side

The Ascend and TEP assumptions on ELCC assumptions are very different. Ascend assumes that the ELCC of renewable resources and storage will decline over the next 30 years whereas TEP keeps their capacity value constant. The divergence in ELCC assumptions between Ascend and TEP result in the portfolios designed by Ascend having significantly more nameplate capacity.

Another source of difference between Ascend and TEP are the market price assumptions. As discussed in Section 3.4.2, Ascend forecasts market prices to remain flat in nominal terms over the next 30 year whereas TEP forecasts market prices to steadily increase.

The table below shows the portfolio capacity by resource type. The Energy Rules portfolios rely much more on renewables and energy storage while the least cost portfolio adds a lot of natural gas capacity.

Table 13: TEP Portfolio Capacity by Resource Type – TEP Assumptions

	TEP Least Cost			TEP Energy Rules 80%			TEP Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	1,679	1,419	1,419	1,679	1,419	1,419	1,679	1,757	-
Coal	516	-	-	516	-	-	516	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	548	1,969	1,969	548	2,669	3,169	548	2,669	3,169
Wind	625	1,075	1,075	625	1,625	1,625	625	1,625	1,625
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	595	1,445	1,445	595	1,445	1,445	595	1,445	1,445
Storage (8 hours)	-	-	-	-	550	800	-	500	800
Storage (12 hours)	-	-	-	-	-	-	-	-	-
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-	-	-	1,757

Table 14: TEP Portfolio Capacity by Resource Type – Ascend Assumptions

	Ascend Least Cost			Ascend Energy Rules 80%			Ascend Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	2,329	3,048	2,725	1,679	1,623	1,972	1,679	1,373	-
Coal	516	-	-	516	-	-	516	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	548	2,169	1,919	548	1,169	3,169	458	2,169	4,169
Wind	625	875	1,419	625	1,875	2,875	625	1,875	2,875
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	595	1,530	2,530	630	2,030	3,030	630	2,030	3,030
Storage (8 hours)	-	-	-	255	1,000	2,000	255	1,000	2,000
Storage (12 hours)	-	-	-	-	-	-	-	250	500
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-	-	-	-

4.2.3 RESULTS

The results of the analysis for TEP are shown in the following tables:

Table 15: Revenue Requirements ($M) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	1,226	1,410	1,540	1,540	2,067
80% Clean	1,224	1,409	1,540	1,687	1,894
Least Cost	1,224	1,409	1,540	1,669	1,874
Difference (100% Clean – Least Cost)	2	1	1	44	193
Difference (80% Clean – Least Cost)	0	0	0	18	19
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	4%	9%	14%	30%

Table 16: Revenue Requirements ($M) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	1,223	1,484	1,650	2,033	3,085
80% Clean	1,223	1,484	1,650	1,978	2,864
Least Cost	1,223	1,424	1,518	1,779	2,365
Difference (100% Clean – Least Cost)	0.30	59.87	131.63	254.05	720.31
Difference (80% Clean – Least Cost)	0	59.70	131.61	198.81	498.88
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Table 17: Revenue Requirement Net Present Value[8] ($M) for 2021 - 2050

	APS Assumptions	Ascend Assumptions
100% Clean	19,196	21,091
80% Clean	18,962	20,775
Least Cost	18,910	19,645
Difference (100% Clean – Least Cost)	286	1,446
Difference (80% Clean – Least Cost)	52	1,130
% Difference (100% Clean – Least Cost)	2%	7%
% Difference (80% Clean – Least Cost)	0%	6%

[8] *Assumes 7% annual discount rate*

Table 18: Average Rate Impacts ($/kWh) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.136	0.141	0.145	0.152	0.167
80% Clean	0.13	0.141	0.145	0.150	0.153
Least Cost	0.135	0.141	0.145	0.148	0.152
Difference (100% Clean – Least Cost)	0.000	0.000	0.000	0.004	0.016
Difference (80% Clean – Least Cost)	0.000	0.000	0.000	0.002	0.002
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	0%	0%	1%	1%

Table 19: Average Rate Impacts ($/kWh) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.135	0.148	0.155	0.181	0.249
80% Clean	0.135	0.148	0.155	0.176	0.231
Least Cost	0.135	0.142	0.143	0.158	0.191
Difference (100% Clean – Least Cost)	0	0.006	0.012	0.023	0.058
Difference (80% Clean – Least Cost)	0	0.006	0.012	0.018	0.040
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Table 20: Average Monthly Residential Bill Impacts[9] ($) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	135.64	140.97	145.09	152.31	167.14
80% Clean	135.42	140.86	145.02	149.99	153.09
Least Cost	135.43	140.86	145.02	148.41	151.53
Difference (100% Clean – Least Cost)	0.21	0.11	0.07	3.90	15.61
Difference (80% Clean – Least Cost)	0.00	0.00	0.00	1.58	1.56
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	0%	0%	1%	1%

[9] Assumes *1,000 kWh monthly consumption per customer*

Table 21: Average Monthly Residential Bill Impacts[10] ($) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	135.32	148.40	155.40	180.73	249.38
80% Clean	135.29	148.38	155.40	175.82	231.49
Least Cost	135.29	142.41	143.00	158.16	191.15
Difference (100% Clean – Least Cost)	0.03	5.99	12.40	22.57	58.23
Difference (80% Clean – Least Cost)	0	5.97	12.40	17.66	40.33
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Note that the revenue requirements and average rates should not be compared between APS and TEP. The revenue requirement for TEP is all-in and includes the costs associated with distribution systems while APS includes only generation and transmission costs. However, distribution costs are considered the same across the different cases and thus the interest lies in the incremental cost relative to the "least cost" scenario. Also, the customer usage assumptions are slightly different between the two utilities causing the average rates to have different base lines.

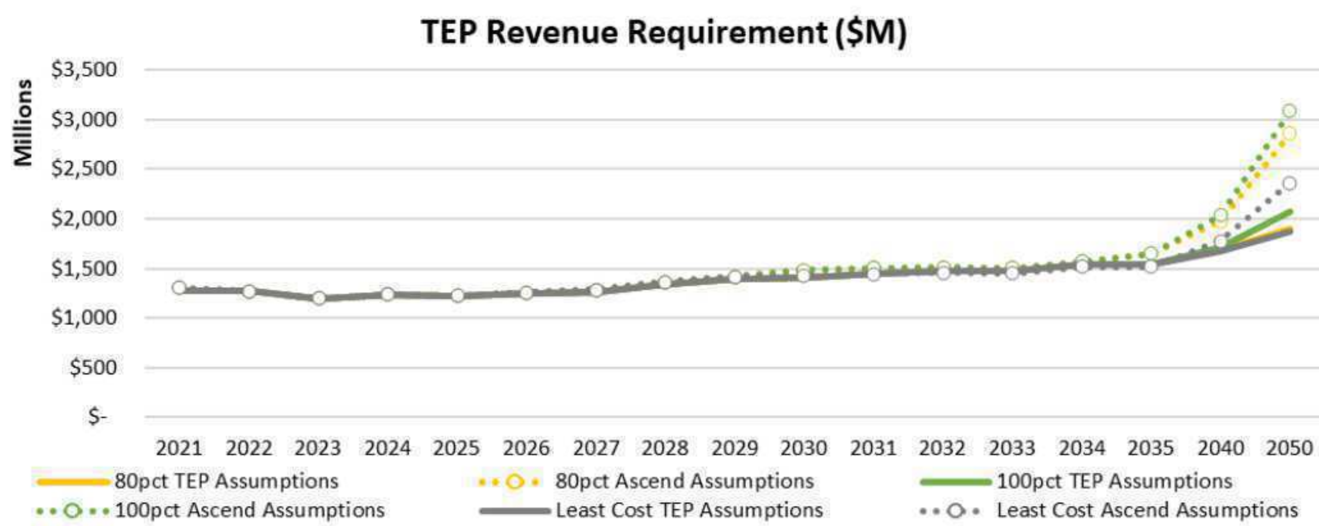


Figure 32: TEP revenue requirement (including transmission expansions)

[10] Assumes *1,000 kWh monthly consumption per customer*

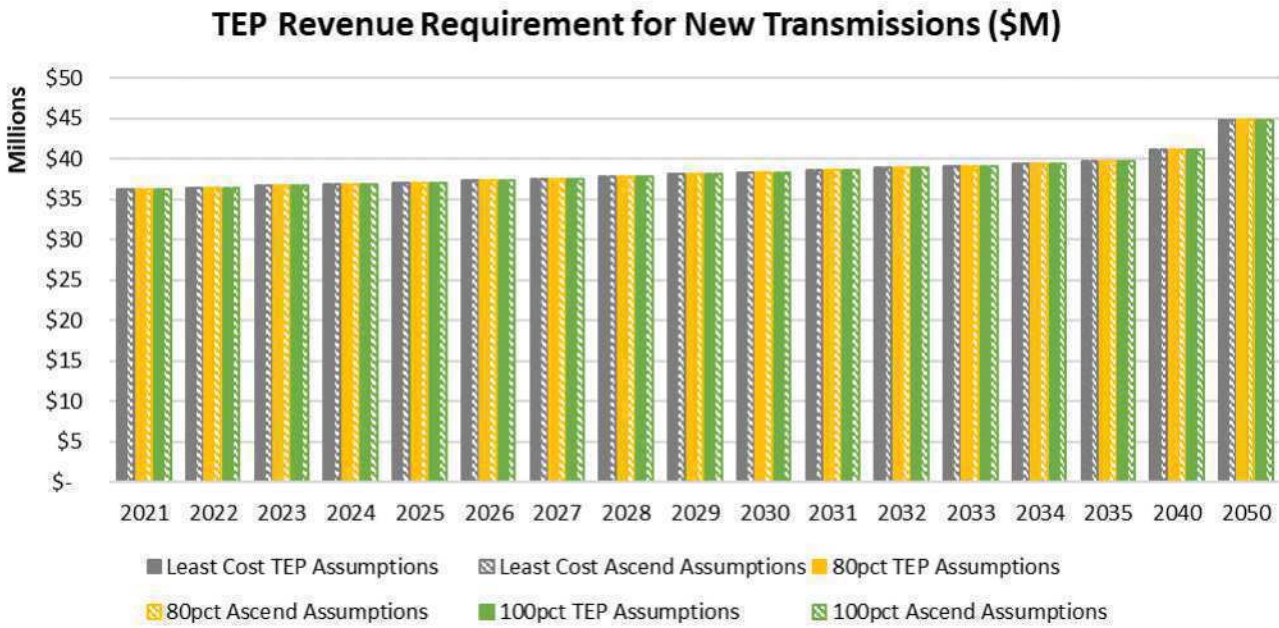


Figure 33: TEP revenue requirement for new transmission expansions

Revenue requirements are similar in the first 15 years for both Ascend and TEP assumptions. However, a strong deviation occurs in years 2040 and 2050 due to major differences in the assumptions. The revenue requirement and therefore the rate increases are mainly driven by the capital costs of new resources. The lower ELCC assumption on renewable resources in the Ascend cases results in portfolios with more nameplate capacity which in turn results in greater revenue requirements. Cost of new transmission lines is included in the revenue requirement and is assumed to be the same across all six cases.

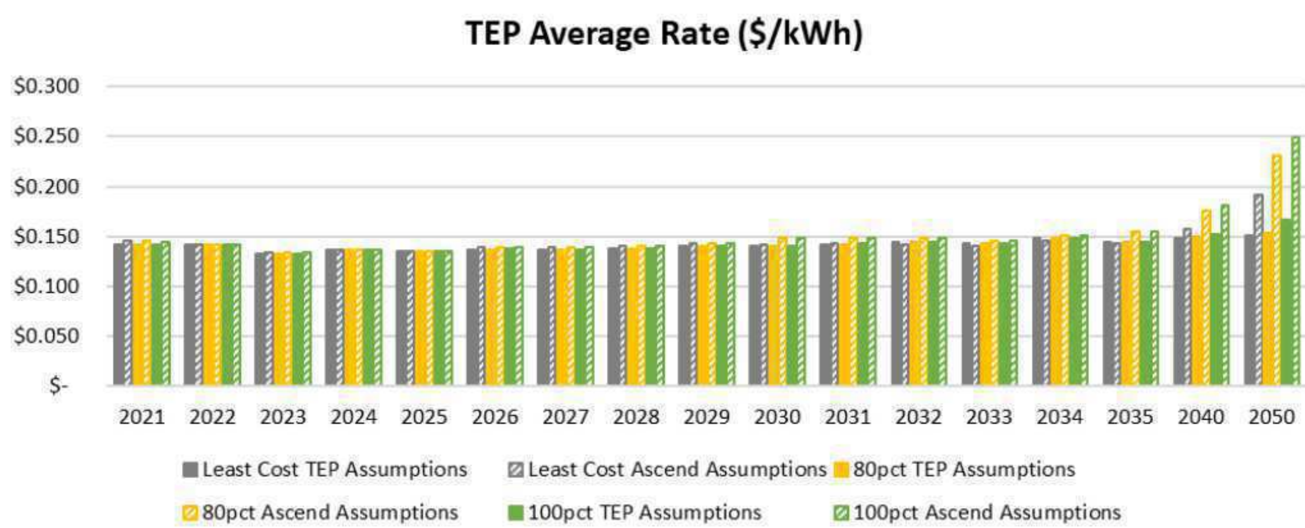


Figure 34: TEP average electricity rate

The “Least Cost” and 80% cases have relatively similar average rates across the 30 years. Post 2040, the 100% case becomes more expensive than its counterparts with the difference more readily apparent using Ascend assumptions.

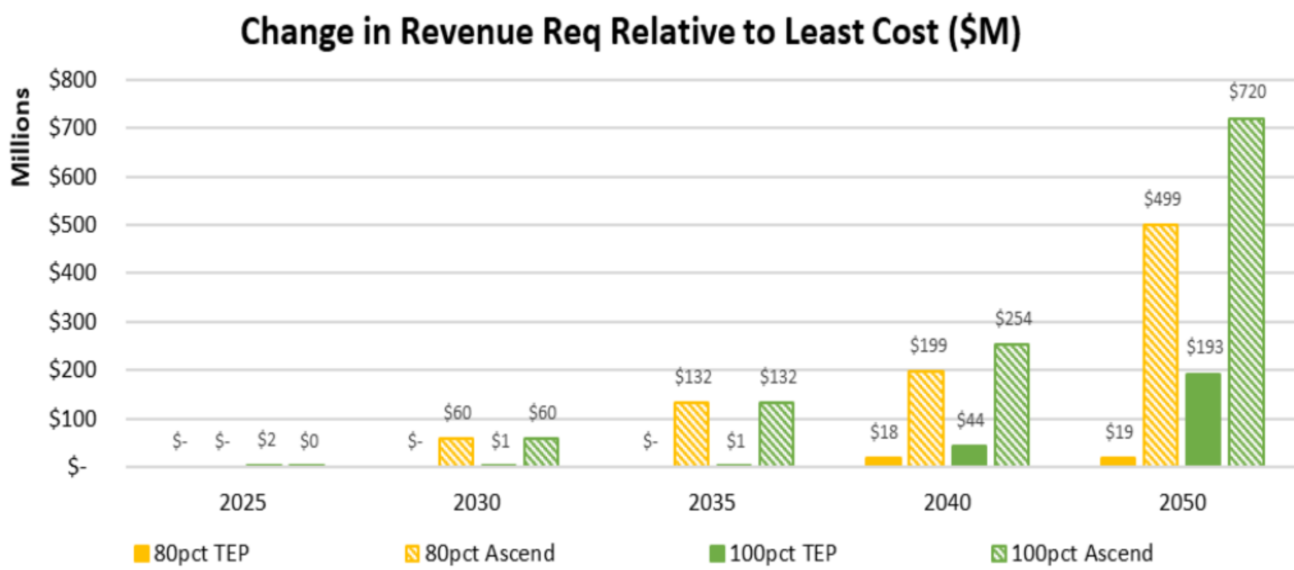


Figure 35: TEP change in revenue requirement relative to the least cost scenario

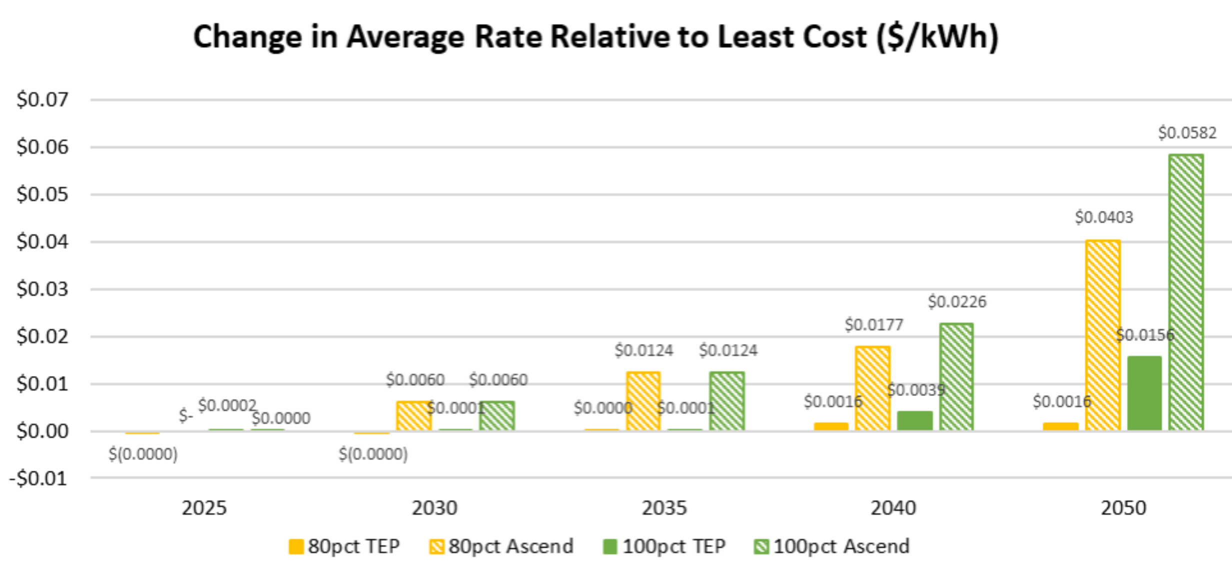


Figure 36: TEP change in average electricity rate relative to the least cost case

Looking at the incremental difference relative to the “Least Cost” case, both energy rules scenarios seem to have a moderate impact on the average rate and revenue requirement.

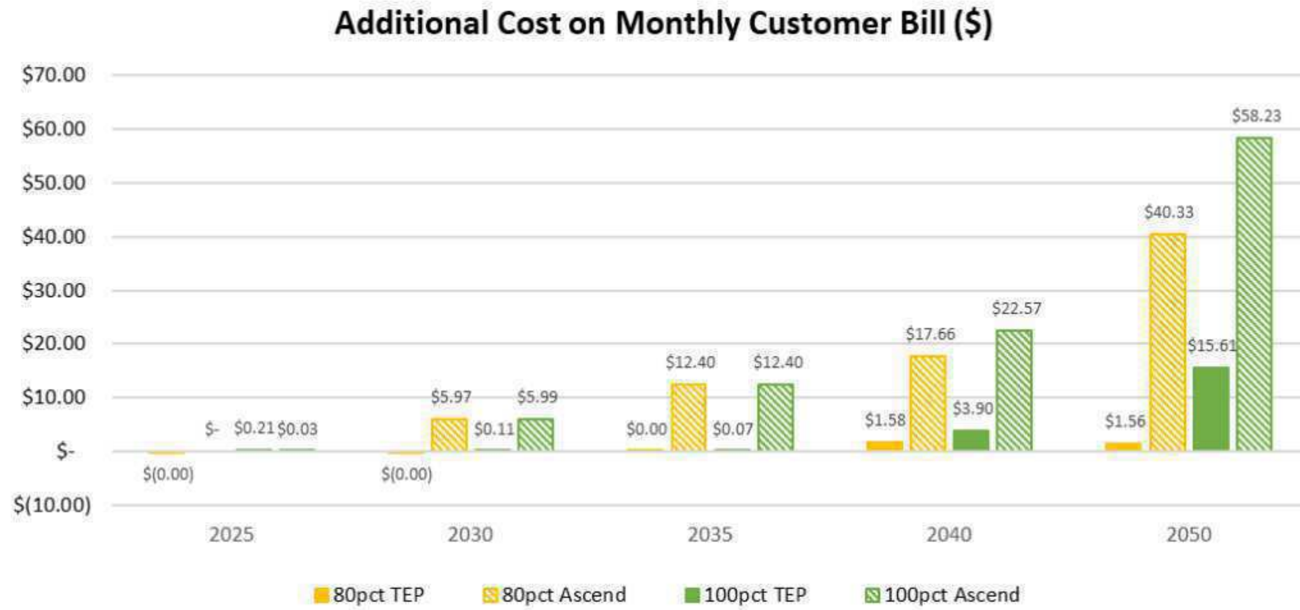


Figure 37: TEP monthly additional cost on electricity bill as a result of adopting the energy rules

The differences in assumptions used by TEP and Ascend provide a range of costs for the Energy Rules. The change in customer rates relative to the least cost portfolios is minimal before 2035. The larger carbon reductions needed after 2035 to meet 80% or 100% reductions drive the average rates up by $0.058/kWh in the Ascend assumptions case by 2050 with the TEP assumptions yielding a smaller rate increase.

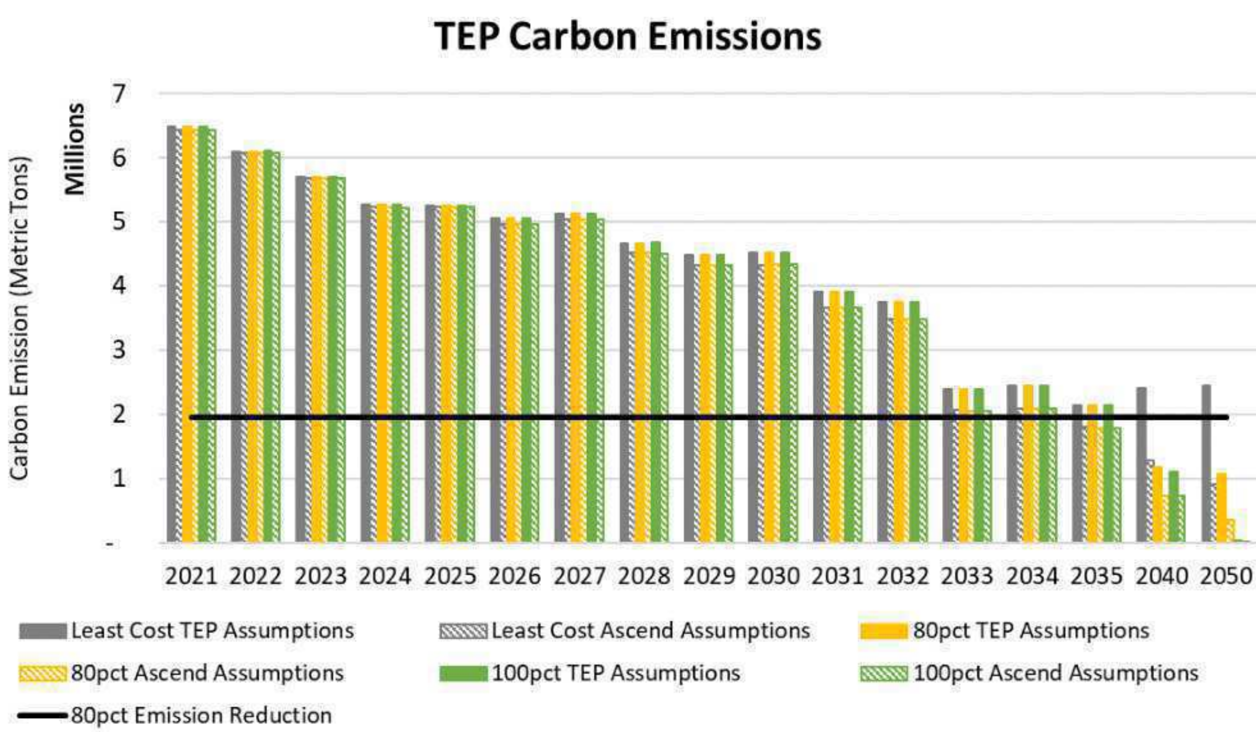


Figure 38: TEP carbon emissions

The retirement of all coal generation by 2032 drives the majority of the carbon reductions through the IRP period. After 2035, the carbon emissions reductions diverge based on the constraints for each portfolio. The energy rules portfolios all reduce emissions by at least 80% in 2050.

The Energy Rules have a small/moderate nominal cost to reach 80% carbon reductions while achieving a 100% by 2050 has a larger cost. Given the influence that capital costs have on the overall cost of the energy rules, the costs of new resources in the 2040s will play an outsized role in the true cost of the Energy Rules. The path to both 80% and 100% reductions in carbon emission rely heavily on renewables and storage. The portfolios that were analyzed for TEP all include the resources necessary to continue decarbonizing the TEP system.

4.3 STUDY LIMITATIONS AND RECOMMENDATIONS FOR FURTHER ANALYSIS

As with any very long-range study, results in the distant future must be taken somewhat with a grain of salt. We have little information as to what technologies will be available or how exactly the power system will evolve. We believe these results are directionally consistent with an emerging consensus[11] that decarbonizing the power sector until at least 80% - 90% clean energy is achievable and cost-effective with today's technology over a timespan covering the next two decades.

Some limitations include:

- The studies only compare three discrete scenarios, none of which were optimized. A more thorough study would leverage capacity expansion algorithms as well as discrete sensitivities to test key assumptions.
- This study was not paired with loss of load probability analysis. We cannot say with confidence that these portfolios are reliable without conducting an independent reliability analysis.
- This study was performed deterministically, meaning we do not analytically capture meaningful uncertainty driven by weather as a fundamental driver of load, renewable output, forced outages, and gas and power price dynamics. A deterministic result only shows a single view of the world versus a distribution of possible outcomes.
- Study is completed with perfect foresight (i.e. model "sees" all prices and optimizes dispatch perfectly) at the hourly level (as opposed to 5-minute intervals), which fundamentally undervalues flexible resources such as batteries in the context of participation in the Western Energy Imbalance Market (EIM).

Analytical studies such as this one, provide important insights into the mechanics of complex systems including how changes in assumptions about future uncertainties would impact the outcomes. The following table highlights key assumptions and how results would be affected if they were more or less than we believe today.

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[11] For example, see NREL study on reaching 100% clean electricity https://www.nrel.gov/news/program/2021/the-challenge-of-the-last-few-percent-quantifying-the-costs-and-emissions-benefits-of-100-renewables.html

Table 22: Understanding the Impacts of Key Uncertainties

Assumption	What would cause costs to be less than expected?	What would cause costs to be more than expected?
Effective load carrying capability (ELCC)	ELCC of wind, solar, and batteries are more than we expect, potentially as a function of portfolio effects and geographic diversity.	ELCC of wind, solar, and batteries are less than we expect, potentially as a function of strong correlation in weather regimes on renewable output.
Technology types and costs	If innovation makes storage dramatically more cost-effective than we expect costs of decarbonization would decrease.	If future technologies do not decline as we expect, then costs to decarbonize would be higher than shown here.
Climate change	Climate impacts are more moderate than we expect, meaning less need to build peaking capacity for heat storms.	Climate impacts are worse than we expect, therefore additional capacity is needed to maintain reliability during more frequent and longer heat storms.
Market structure	If LSEs join a regional RTO, the cost of decarbonization due to better coordination of resources across the West.	Not applicable.
Transmission	Federal spending and permitting reforms support additional transmission that unlocks more low-cost renewable energy. Higher adoption and targeted deployment of distribution sited storage and distributed energy resources reduces the need for transmission spending.	No federal spending or permitting reform. Low adoption/sub-optimal deployment of distributed energy resources.

Should the ACC feel more analysis would be beneficial to support regulatory policy making, Ascend makes the following recommendations:

1. Commission a study using an independent analytical firm (and/or national lab, ASU, etc.) to model pathways to 100% clean energy by 2050.
2. Make sure to hire an analyst that uses best-in-class "HD PCMs." There are several that have been developed by various modeling firms.
3. Include other sectors in the analysis, such as transportation and building electrification.
4. Investigate both supply and demand-side solutions.
5. Utilize capacity expansion and scenario design.
6. Include a stakeholder engagement process.
7. Make sure to include reliability analysis, resiliency, and climate impacts.
8. Allot a sufficient amount of time and resources to make the analysis robust and meaningful. Nine months to one year is typical.

5 Appendix

5.1 APS LOAD AND RESOURCE TABLES

Below are the load and resource tables developed by APS and the Ascend team for assessing the costs of the proposed energy rules.

Load and Resource Table for Least Cost Portfolio

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(486)	(890)	(1,207)	(1,553)	(1,914)
Distributed Generation (MW)	(4)	(39)	(132)	(225)	(283)	(286)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,986**	**8,726**	**9,503**	**10,437**	**13,244**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,224	1,362	1,510	1,668	2,116
Total Firm Load Obligation (MW)	**8,366**	**9,210**	**10,088**	**11,012**	**12,105**	**15,360**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	2,995	3,489	1,891	1,891	1,891	1,891
NGCT	1,545	1,545	1,545	1,545	1,545	1,545
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-

Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32
Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,043	7,150	5,552	4,582	4,582	4,582
Renewables (Solar, Wind, Geothermal, Biomass)	489	468	401	363	297	10
Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,251**	**7,812**	**6,146**	**5,138**	**5,071**	**4,784**

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	1,677	2,219	2,761	3,303
NGCT (frame)	-	724	1,810	2,896	2,896	5,068
Solar	-	200	200	500	1,050	2,450
Wind	-	362	450	450	600	2,250
Biomass/Biogas	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	550	550	850	1,400	1,850
Storage (8 hours)	-	-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-
Microgrid	-	206	231	281	281	281
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	724	3,487	5,115	5,657	8,371
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	159	174	206	260	782
Energy Storage	-	371	390	560	889	1,153
Other (Microgrid, Market Purchases)	150	206	231	281	281	281
Total Contribution to Peak from Future (MW)	**150**	**1,460**	**4,282**	**6,161**	**7,086**	**10,587**

Total Planning Capacity	2020	2025	2030	2035	2040	2050
Total Capacity (MW)	8,401	9,272	10,429	11,299	12,157	15,371
Capacity Position (MW)	35	62	340	287	52	11

Load and Resource Table for Energy Rules 80% Portfolio

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(754)	(1,479)	(2,155)	(2,832)	(4,111)
Distributed Generation (MW)	(4)	(40)	(133)	(206)	(200)	(130)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,716**	**8,136**	**8,573**	**9,241**	**11,203**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,184	1,274	1,367	1,476	1,786
Total Firm Load Obligation (MW)	**8,366**	**8,900**	**9,410**	**9,940**	**10,717**	**12,989**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	2,991	3,489	1,891	1,891	1,891	1,891
NGCT	1,545	1,545	1,545	1,545	1,545	1,545
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-
Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32

Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,039	7,150	5,552	4,582	4,582	4,582
Renewables (Solar, Wind, Geothermal, Biomass)	485	464	374	324	259	5
Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,243**	**7,807**	**6,120**	**5,099**	**5,033**	**4,779**

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	1,135	1,135	1,135	570
NGCT (frame)	-	-	362	724	724	724
Solar	-	700	1,900	3,400	5,525	8,925
Wind	-	462	1,400	2,250	2,400	4,300
Geothermal	-	-	-	-	-	250
Renewable Fuels	-	-	-	-	-	1,448
Storage (4 hours)	-	1,050	1,700	3,600	3,550	3,400
Storage (8 hours)	-	-	-	-	1,250	1,250
Storage (12 hours)	-	-	-	-	200	3,500
Microgrid	-	31	56	131	131	131
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	-	1,497	1,859	1,859	1,294
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	372	576	653	599	2,678
Energy Storage	-	694	1,249	2,211	3,184	4,153
Other (Microgrid, Market Purchases)	150	31	56	131	131	131
Total Contribution to Peak from Existing (MW)	**150**	**1,097**	**3,378**	**4,854**	**5,773**	**8,256**

Total Planning Capacity	2020	2025	2030	2035	2040	2050
Total Capacity (MW)	8,393	8,904	9,497	9,953	10,806	13,035

Capacity Position (MW)	26	4	88	13	89	46

Load and Resource Table for Energy Rules 100% portfolio

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(754)	(1,479)	(2,155)	(2,832)	(4,111)
Distributed Generation (MW)	(4)	(40)	(133)	(206)	(200)	(130)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,716**	**8,136**	**8,573**	**9,241**	**11,203**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,184	1,274	1,367	1,476	1,786
Total Firm Load Obligation (MW)	**8,366**	**8,900**	**9,410**	**9,940**	**10,717**	**12,989**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	2,995	3,489	1,891	1,891	1,891	-
NGCT	1,545	1,545	1,545	1,545	1,545	-
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-
Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32
Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,043	7,150	5,552	4,582	4,582	1,146
Renewables (Solar, Wind, Geothermal, Biomass)	485	464	374	324	259	4

Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,247**	**7,807**	**6,120**	**5,099**	**5,033**	**1,342**

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	1,135	1,135	1,135	-
NGCT (frame)	-	-	362	724	724	-
Solar	-	700	1,900	3,400	6,575	7,375
Wind	-	462	1,400	2,250	2,600	3,300
Geothermal	-	-	-	-	-	250
Renewable Fuels	-	-	-	-	-	4,706
Storage (4 hours)	-	1,050	1,700	3,600	3,550	5,000
Storage (8 hours)	-	-	-	-	1,250	5,000
Storage (12 hours)	-	-	-	-	1,000	3,500
Microgrid	-	31	56	131	131	131
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	-	1,497	1,859	1,859	-
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	372	576	653	646	5,712
Energy Storage	-	694	1,249	2,213	3,643	5,830
Other (Microgrid, Market Purchases)	150	31	56	131	131	131
Total Contribution to Peak from Existing (MW)	**150**	**1,097**	**3,378**	**4,857**	**6,280**	**11,673**

Total Planning Capacity	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Total Capacity (MW)	8,397	8,904	9,497	9,956	11,313	13,015
Capacity Position (MW)	30	4	88	15	596	26

5.2 TEP LOAD AND RESOURCE TABLES

Below are the load and resource tables developed by TEP and the Ascend team for assessing the costs of the proposed energy rules.

Load and Resource Table for Least Cost portfolio – TEP Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(8)	(43)	(69)	(101)	(130)	(189)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Least Cost	**2,538**	**2,584**	**2,785**	**2,859**	**3,009**	**3,269**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	381	388	418	429	451	490
Total Firm Load Obligation (MW)	**3,096**	**3,152**	**3,398**	**3,488**	**3,671**	**3,988**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	1,146
NGCT	212	212	91	91	91	91
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)		30	30	30	30	30

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	500	500
NGCT (frame)	-	-	-	-	-	-

NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	1,800	1,800
Wind	-	-	200	500	700	700
Geothermal	-	-	-	-	-	-
Biomass/Biogas	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)		-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – TEP Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Rules	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	1,146
NGCT	212	212	91	91	91	91
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-

Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)	-	30	30	30	30	30

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,500	3,000
Wind	-	-	200	500	1,250	1,250
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)	-	-	-	-	550	800
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 100% portfolio – TEP Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Rules	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050

Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	156	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)	-	30	30	30	30	30

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	182	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,500	3,000
Wind	-	-	200	500	1,250	1,250
Renewable Fuels	-	-	-	-	-	1,757
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)	-	-	-		550	800
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Least Cost portfolio – Ascend Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(8)	(43)	(69)	(101)	(130)	(189)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)

Net System Peak (MW)	2,538	2,584	2,785	2,859	3,009	3,269
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	381	388	418	429	451	490
Total Firm Load Obligation (MW)	**3,096**	**3,152**	**3,398**	**3,488**	**3,671**	**3,988**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)		30	30	30	30	-

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	750
NGCT (frame)	-	-	-	-	-	-
NG RICE	-	225	650	950	1,675	2,725
Solar	-	125	250	1,500	2,000	2,750
Wind	-	-	200	500	750	1,250
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,500	2,500
Storage (8 hours)		-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – Ascend Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370

Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW)	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	-
Wind	80	425	425	375	375	-
Storage (4 hours)	-	30	30	30	30	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	250	1,790
Solar	-	125	250	1,500	2,000	4,000
Wind	-	-	200	500	1,500	2,500
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	600	1,415	2,000	3,000
Storage (8 hours)	-	-	255	600	1,000	2,000

Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – Ascend Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW)	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	-
Wind	80	425	425	375	375	-
Storage (4 hours)	-	30	30	30	30	-

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-

NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,000	4,000
Wind	-	-	200	500	1,500	2,500
Renewable Fuels	-	-	-	-	-	1,725
Storage (4 hours)	-	150	600	1,415	2,000	3,000
Storage (8 hours)	-	-	255	600	1,000	2,000
Storage (12 hours)	-	-	-	-	250	500